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The environmental factors associated with alternative fuel/energy cycles were analyzed to provide a basis for making explicit judgments regarding economics and environmental trade-offs.

A preliminary compilation of effluent data was developed for those energy sources considered commercially viable in the 1975 to 1990 time period. A preliminary methodology was developed for organizing the compiled effluent data, for evaluating the combined effects of extraction, transportation, processing, and utilization of fuels to produce energy, and for ranking the fuel/energy systems environmentally. The data bank and computer program for the ranking procedure are extant. The computerized methodology enables an energy system evaluator to test preferred weighting factors readily.

Based on this evaluation of the overall fuel/energy cycle, air emissions associated with coal utilization can be reduced to approximately those from natural gas systems, with an attendant increase in water pollution or solid waste production. This improvement can be accomplished through the application of advanced treatment or control technology projected to be available during the early part of the 1975 to 1990 time period. Later in the period further technology advance will become available for also minimizing the water and solid waste burdens produced through coal utilization.

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ENVIRONMENTAL CONSIDERATIONS IN FUTURE ENERGY GROWTH

by

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EPA Review Notice

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ABSTRACT

The environmental factors associated with alternative fuel/energy cycles were analyzed to provide a basis for making explicit judgments regarding economics and environmental trade-offs.

A preliminary compilation of effluent data was developed for those energy sources considered commercially viable in the 1975 to 1990 time period. A preliminary methodology was developed for organizing the compiled effluent data, for evaluating the combined effects of extraction, transportation, processing, and utilization of fuels to produce energy, and for ranking the fuel/energy systems environmentally. The data bank and computer program for the ranking procedure are extant. The computerized methodology enables any energy system evaluator to test preferred weighting factors readily.

Based on this evaluation of the overall fuel/energy cycle, air emissions associated with coal utilization can be reduced to approximately those from natural gas systems, with an attendant increase in water pollution or solid waste production. This improvement can be accomplished through the application of advanced treatment or control technology projected to be available during the early part of the 1975 to 1990 time period. Later in the period further technology advances will become available for also minimizing the water and solid waste burdens produced through coal utilization.

Qualitative environmental relationships were evaluated for advanced energy systems considered developmental during the 1975 to 1990 time period. Those judged to exhibit major potential for supplying significant portions of future energy demand with reduced environmental impact are: geothermal, solar, and nuclear fusion.

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SECTION I

CONCLUSIONS

1. The major results of this study may be summarized as follows:

(a) A preliminary compilation of effluent data has been developed for those energy sources considered commercially viable in the 1975 to 1990 time period. These data represent readily available information within EPA and private industry concerning the quantity of residual pollutants produced during the extraction, conversion, transportation and stationary use of fuels to produce electricity or direct heating under best available conditions of environmental control. The incremental cost of control and the overall cost of electricity produced also have been compiled.

(b) A preliminary methodology has been developed for organizing the effluent data collected and for combining the emission data for each module into a single environmental index for each energy system. The value of such an index is that it provides a tool for making explicit the value judgments of any system evaluator with respect to the relative environmental impact of energy systems. This methodology has been applied in the context of this study to develop a gross environmental ranking of the energy systems considered. Ultimately, such a ranking of energy systems must be done on the basis of specific local environmental impacts which may vary considerably the weighting factor associated with each module and pollutant.

(c) From the data compiled in this study it is clear that natural gas systems produce electrical energy with the least associated environmental burdens. Moderate air emissions occur in the extraction and combustion phases but other burdens are small or negligible. Electrical energy produced by residual fuel oil systems gives rise to greater environmental burdens. Significant air emissions occur in the refining and combustion phases and water pollutants are produced in the refining phase. Eastern coal-based systems, which employ current technology, produce still greater environmental burdens, chiefly in the form of solid waste from extraction and combustion and air emissions from combustion.

(d) The application of improved technology in the areas of fuel conversion and pollution control can be expected to achieve substantial reduction in the overall environmental burdens. The control of SO_2 emissions from coal and oil combustion to achieve ambient air quality standards can be technically achieved in the 1975 to 1990 time period. Similar conclusions may be drawn regarding coal conversion technologies such as liquefaction and gasification. However, such treatment or control technologies must transfer the inherent fuel sulfur plus chemical reactant to another media creating water pollutants or solid waste products. Near the end of the 1975 to 1990 time period regenerative stack gas cleaning technologies, such as MgO scrubbing, and advanced combustion techniques, such as fluidized-bed combustion of coal and oil, can be made available which will achieve equivalent reduction of air emissions with only a moderate increase in the production of solid waste. This conclusion can be illustrated by comparing the approximate total annual air emissions associated with the extraction, transportation, and combustion of Eastern coal to produce 1000 MW of electricity for: coal burned in a conventional boiler, 235,000 tons; conventional boiler plus wet limestone scrubbing, 60,000 tons; conventional boiler plus MgO scrubbing, 60,000 tons; and fluidized-bed combustion of coal plus combined cycle, 40,000 tons. The corresponding approximate total annual production of solid waste for the same four systems is: 500,000- 1,300,000- 530,000- and 700,000 tons, respectively. By comparison, the total of the air emissions associated with the extraction, transportation, and combustion of natural gas is about 80,000 tons. The solid waste production for the natural gas system is negligible. Similarly the approximate total annual air emissions from the extraction, transportation, refining, and combustion of oil could be reduced by wet limestone scrubbing of the power pland stack gas from about 120,000 tons to about 75,000 tons with an associated increased production of 322,500 tons of solid waste. Application of MgO scrubbing would achieve the same level of air emission with minimal increase of solid waste production over no scrubbing.

(e) Based on this evaluation the air emissions from coal-based systems can be reduced by application of advanced technology to less than those of natural gas, while minimizing the attendant increase in solid waste.

(f) The data bank and computer program for the ranking procedure are extant. The computerized methodology makes it simple to test the preferred weighting factors of any energy-system evaluator.

(g) The pertinent environmental factors have been identified for those advanced energy sources considered to be developmental during the 1975 to 1990 time period. The qualitative environmental relationships have been evaluated by a panel through value judgments and subjective considerations. Advanced energy sources judged to exhibit major potential for supplying significant portions of future energy demand with reduced environmental impact are: geothermal, solar, and nuclear fusion.

2. The very broad scope of the project and the short time available for this preliminary study have necessarily limited the effort to an overview. Nevertheless, the assembled data represent a unique compilation of emission inventories which can serve as a foundation and point of departure for both technical investigators and policy makers.

3. Emission data for hazardous trace materials are grossly inaccurate or not available.

SECTION II

RECOMMENDATIONS

This program was limited by the short time available to compilation of readily available data, selection of limited environmental categories and first-order application of weighting factors. It is recommended that additional effort be undertaken to address key issues not adequately treated in this initial study. These key issues include:

1. Refinement of the emissions assessments made in this initial study to improve the validity of the results.

2. Development of data for atmospheric emissions of trace metals and fine particulates, and for water emissions of trace metals and other parameters for which incomplete data exists for some modules.

3. Comparison of impacts from radioactivity with material pollutants.

4. Comparison of energy (thermal effluents) residuals and material residuals.

5. Location of impact (generation of impact in one location and the use of energy in another).

6. Relative weighting of air, water, solid waste, land impacts (land use, waste disposal, strip mining, etc.).

7. Extension of the existing emissions data to include evaluation of the overall environmental impacts in the ecology and social categories, and the incorporation of these impacts into the evaluation of alternative energy systems.

8. Nuclear reactor accidents.

Additional effort in this area also should include an evaluation of methodology to aggregate impacts at various levels as an aid in decision making. Aggregation could include impacts at the levels of

Site ——> Region ——> National

Process ——> Module ——> System .

SECTION III

INTRODUCTION

One of the many activities in which the Environmental Protection Agency is engaged is the assessment of the comparative environmental impacts of various fuel sources and energy cycles. This is being done in order to provide a basis for recommending environmentally preferred energy policy initiatives which may be required to meet future energy demands. The Columbus Laboratories of Battelle Memorial Institute is assisting the Environmental Protection Agency in this activity by analyzing the available, pertinent emission information and providing to the Environmental Protection Agency the projected total environmental burden associated with alternative approaches to the future supply of energy. The overall objective of Battelle's efforts is to provide EPA with the necessary information regarding the environmental emissions of alternative energy cycles to permit explicit judgments regarding economic and environmental trade-offs. This will permit the formulation and execution of sound policy in this critical area.

To support the activities of EPA in this area, Battelle's Columbus Laboratories submitted a proposed research program on October 17, 1972, which consisted of three tasks. The first task was concerned with a projection of the environmental burden of base line fuel-supply projections during the period 1975 to 1990. It was proposed that this effort be based on a comparative analysis of published long-term fuel supply/demand projections. It further was proposed that this be accomplished for both existing and developmental technologies involved in the various segments of the energy systems. Task 1 thus included the identification and quantification of the environmental emissions of alternative fuel supplies commercially available in the 1975 to 1990 time period. The sources of energy under consideration in this portion of the study were identified as coal, oil, natural gas, and nuclear fission. It was explicitly stated that, because of the short time available for this study, the impacts would be quantified in terms of effluent quantities and not effluent effects. It further was established that the utilization segment of the energy cycle would be concerned only with the generation of electrical power and with space heating.

Also included in the first task was the identification and qualification of the potential environmental burden which would result from the commercialization of advanced technologies affecting energy supply and demand which may be under development in the 1972 to 1990 time period. These included fusion, solar energy, geothermal, tidal, fuel cells, thermoelectricity, insulation, and waste-heat recapture.

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The second task included in the proposed research program of October 17, 1972, included a quantification to the maximum extent possible of the effectiveness and economic costs of pollution control for each alternative energy supply and technology considered in Task 1. These were to be considered in terms of common indices to permit comparison of alternatives. It further was proposed that wherever possible pollution control would be considered as that necessary to achieve existing standards or new standards which are anticipated as a result of Federal or environmental legislation, or alternatively, pollution control would apply the "best available" technology.

The third task which was proposed was the ranking of all alternative energy supplies and technologies from best to worst, so far as environmental burden is concerned. The environmental effects of each phase of the energy cycle were to be considered and separate rankings were made for the commercially available energy supplies and for the developmental technologies.

It was proposed that for each of the tasks the information to be analyzed by Battelle would be drawn from published literature, from experience of Battelle staff members in various fields, and from members of the EPA staff. It was emphasized that access to EPA information was vital to the success of the program and that every effort must be made to expedite the exchange of information between EPA and Battelle.

The proposed program was accepted by EPA and work was begun on October 20, 1972. This report is concerned with the results of the study. The body of the report is divided into four basic segments. The first segment deals with the fossil-fuel energy systems, the second with nuclear energy systems, and the third with advanced energy systems. The final segment of the body of the report is concerned with the results and conclusions drawn from the study. The appendices to the report contain discussions of the technology, the sources and quantities of pollutants, and the effectiveness and cost of pollution control techniques for the significant segments of the fuel/energy picture.

The very broad scope of the subject and the short time available for this preliminary study have necessarily limited the effort to an overview. A data base of environmental emissions has been compiled from readily available information, and a preliminary methodology has been developed for ranking the fuel/energy systems on the basis of environmental burden. These elements are extant and can serve as a framework for more detailed analysis and for the addition of new data on emissions and technologies as it is developed if the program is extended and expanded.

SECTION IV

FOSSIL-FUEL ENERGY SYSTEMS

It is anticipated that in the time period of concern to the study--1972 to 1990--fossil fuels will continue to be the dominant source of energy in the United States. For this reason, considerable attention has been given to the analysis of the many and varied energy systems currently in use or under development which utilize fossil fuels.

The complexity of the environmental factors associated with the utilization of fossil fuels requires that the environmental impact of alternative energy sources must be analyzed for the entire energy system from extraction through utilization. This, in turn, requires a systematic approach which will accommodate the large number of variables involved and which will result in an evaluation of energy systems which reflects all of the variables. The modular approach chosen for this study permits such a systematic evaluation. Because of the limitations in the data base, the environmental impact of each module has been evaluated on the basis of emissions, not effects as ultimately should be done to permit development of a more meaningful ranking methodology.

TECHNICAL APPROACH

Information Procurement

The procurement of pertinent information within the brief time span of the study and subsequent analysis of that information was accomplished by close cooperation with various members of the EPA staff. Both published and unpublished information was provided by the EPA for the study. Other information was procured from Battelle's library, as well as other libraries, and from consultants and Battelle staff members knowledgeable in the fields involved. Considerable numbers of documents have been acquired during the course of the study and are being maintained in the project file for future reference.

In many cases, pertinent information--particularly that concerned with environmental burden and cost of environmental control--was not available. In such cases, lack of information has been noted and the need for its development emphasized.

Modular Approach

The pathways by which various fossil fuels are utilized or processed and converted to other forms of energy are many and varied. In order to assess the efficiency of energy utilization and the environmental burden for the various optional energy systems which utilize fossil fuels, a modular approach has been used. In general, the modules, defined as a distinct phase in a fuel/energy system, fall within one of five categories: the extraction or procurement of the fuel from its source, processing of the fuel, the conversion of the fuel to a different form of energy, transportation, and the utilization of the fuel. This approach allows ready identification of those phases of the fuel/energy system which contribute a major share of the environmental burden. It also provides a data base for extensive analysis of a large number of possible system options. A list of the important modules to be considered is given in Table 1.

A very large number of possible pathways from the extraction of a fuel to utilization of the fuel exist. A conceptual view of the modular relationships of importance are presented for coal, oil, and gas in Figures 1 through 5. From these diagrams, a list of systems composed of from two to five modules has been constructed and is presented in Table 2. The list does not represent all possible combinations of modules but rather those considered to be of major importance.

Fifty selected modules have been analyzed for energy efficiency and environmental burden during the course of the first segment of the study. A list of these modules is given in Table 3.

In Appendices C through T, each of the modules under consideration is defined and described. The energy being used in that particular module is quantified, the effectiveness and cost of pollution control is developed, and the various environmental burdens are listed and quantified where the data are available. The components of environmental burden considered for each module include emissions of air and water pollutants, solid waste produced, and the land use required by the operations involved in the module.

System Description and Assessment

The modules described in the foregoing section have been used as building blocks for the various potential energy systems. In the study of electric power generation systems, 15 selected coal systems, 2 mixed-fuel (coal and municipal refuse) systems, 6 oil systems, and 2 gas systems have been described and analyzed. These include the important options open to the nation for meeting the projected energy deficit. In addition, 5 systems have been analyzed in which the end use of the energy is space heating. The overall environmental burden for each

TABLE 1. MODULES OF SIGNIFICANCE IN THE ANALYSIS OF ENVIRONMENTAL IMPACTS

Gas Extraction, Processing, Transportation, and Utilization Options

EXTRACTION AND CLEANING
Gas Extraction and Cleaning/Continental (North America Exclusive of Arctic Regions)
Gas Extraction and Cleaning/Off-Shore
Gas Extraction and Cleaning/Arctic
Gas Extraction and Cleaning/Overseas

TRANSPORT
Gas Pipeline (Conventional)
Gas Pipeline (Arctic)
Cryogenic Tanker

STORAGE
Storage/Domestic
Storage/Tanker

UTILIZATION
Conventional Boiler
Combined Cycle
Space Heating

Oil Extraction, Conversion, Secondary Processing, Transportation, and Utilization Options

EXTRACTION
Oil-Gas Well/Continental
Oil-Gas Well/Off Shore
Oil-Gas Well/Overseas

TRANSPORT OF CRUDE
Oil Pipeline (Conventional)
Oil Pipeline (Arctic)
Tanker

CONVERSION OF CRUDE
U.S. Refinery
Topping Operations (Overseas)
Topping Operations (Domestic)

PROCESSING OF FRACTIONS
Residual Desulfurization
Naphtha No. 2 Fuel Production
Heavy Oil Gasification
Light Oil Gasification
Blending Fuel Oil

TABLE 1. (continued)

TRANSPORT OF PRODUCTS
Barge
Tanker
Pipeline

UTILIZATION
Conventional Boiler
Conventional Boiler/Flue Gas Cleaning
Combined Cycle
Fluid Bed Combustor
Space Heating

Coal Extraction, Processing, Transportation, and Utilization Options

EXTRACTION
Surface Mine (Eastern Coal)
Surface Mine (Western Coal)
Underground Mine (Eastern Coal)

TRANSPORT OPTIONS (Before Processing)
Rail
Barge

TREATMENT OR CONVERSION PROCESSES
Physical Coal Cleaning
Chemical Leaching
Solvent Refining
Gasification (Low Btu)
Gasification (High Btu)

TRANSPORT OPTION (After Processing)
Rail
Barge
Coal Slurry Pipeline
Gas Pipeline

UTILIZATION PROCESSES
Conventional Boilers
Combined Cycle
Fluid Bed Combustor
Conventional Boiler/Flue Gas Cleaning
Space Heating

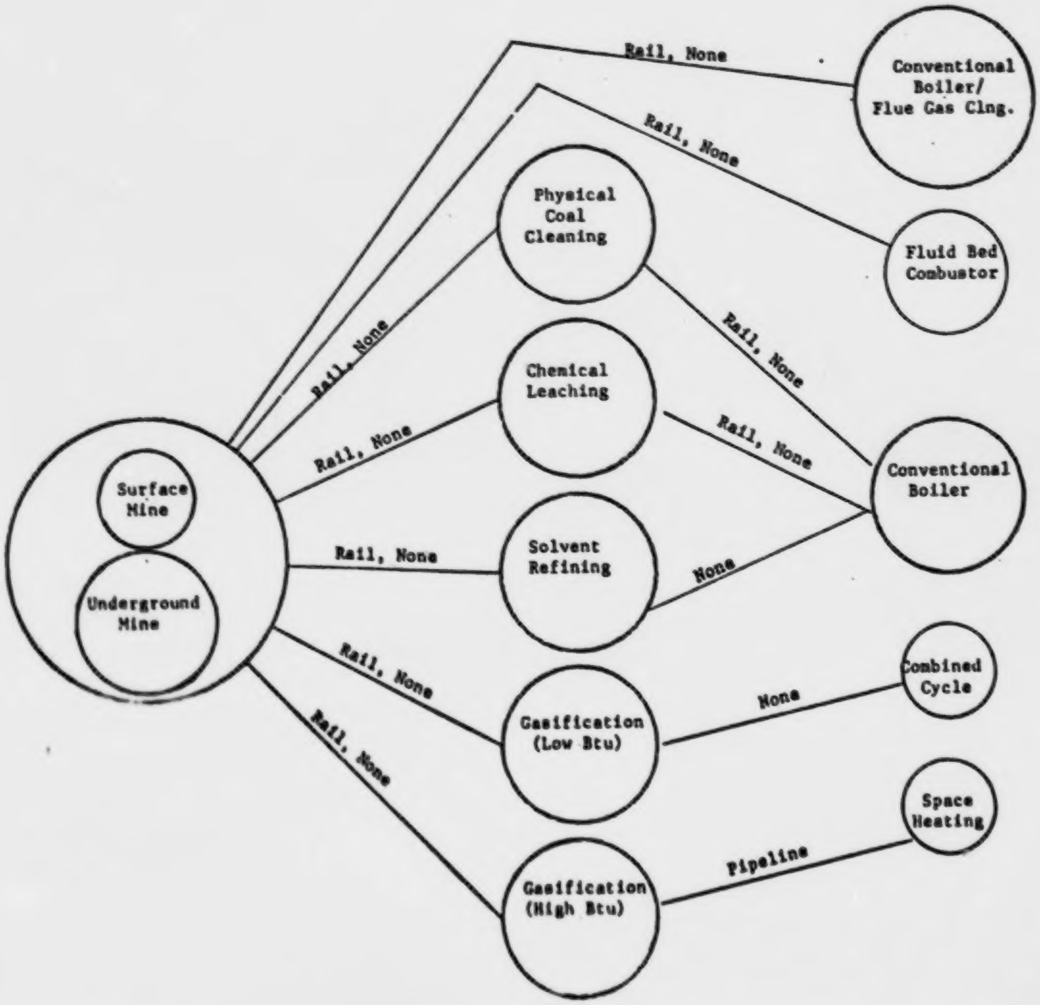
Rail, None
Conventional Boiler/ Flue Gas Clng.
Rail, None
Physical Coal Cleaning
Fluid Bed Combustor
Rail, None
Rail, None
Chemical Leaching
Rail, None
Rail, None
Conventional Boiler
Surface Mine
Underground Mine
Rail, None
Solvent Refining
None
Rail, None
Rail, None
Gasification (Low Btu)
None
Combined Cycle
Space Heating
Pipeline
Gasification (High Btu)

FIGURE 1. SCHEMATIC REPRESENTATION OF MODULAR RELATIONSHIPS - HIGH SULFUR EASTERN COAL

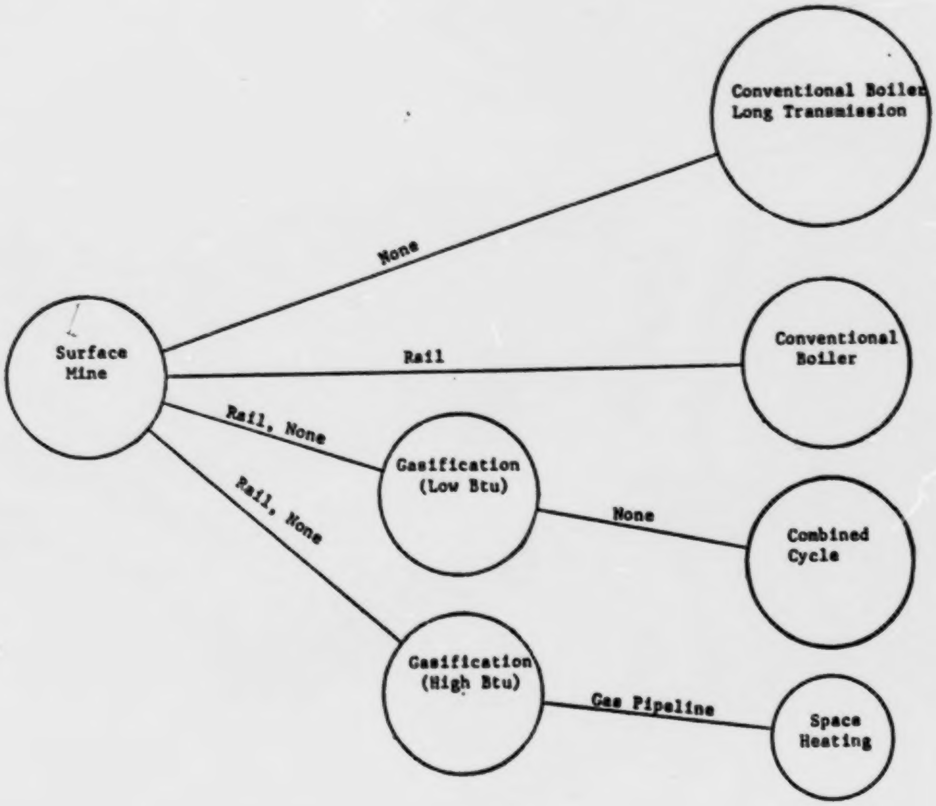
Conventional Boiler
Long Transmission
None
Surface
Mine
Rail
Conventional
Boiler
Rail, None
Gasification
(Low Btu)
Rail, None
None
Combined
Cycle
Gasification
(High Btu)
Gas Pipeline
Space
Heating

FIGURE 2. SCHEMATIC REPRESENTATION OF MODULAR RELATIONSHIPS - LOW SULFUR WESTERN COAL

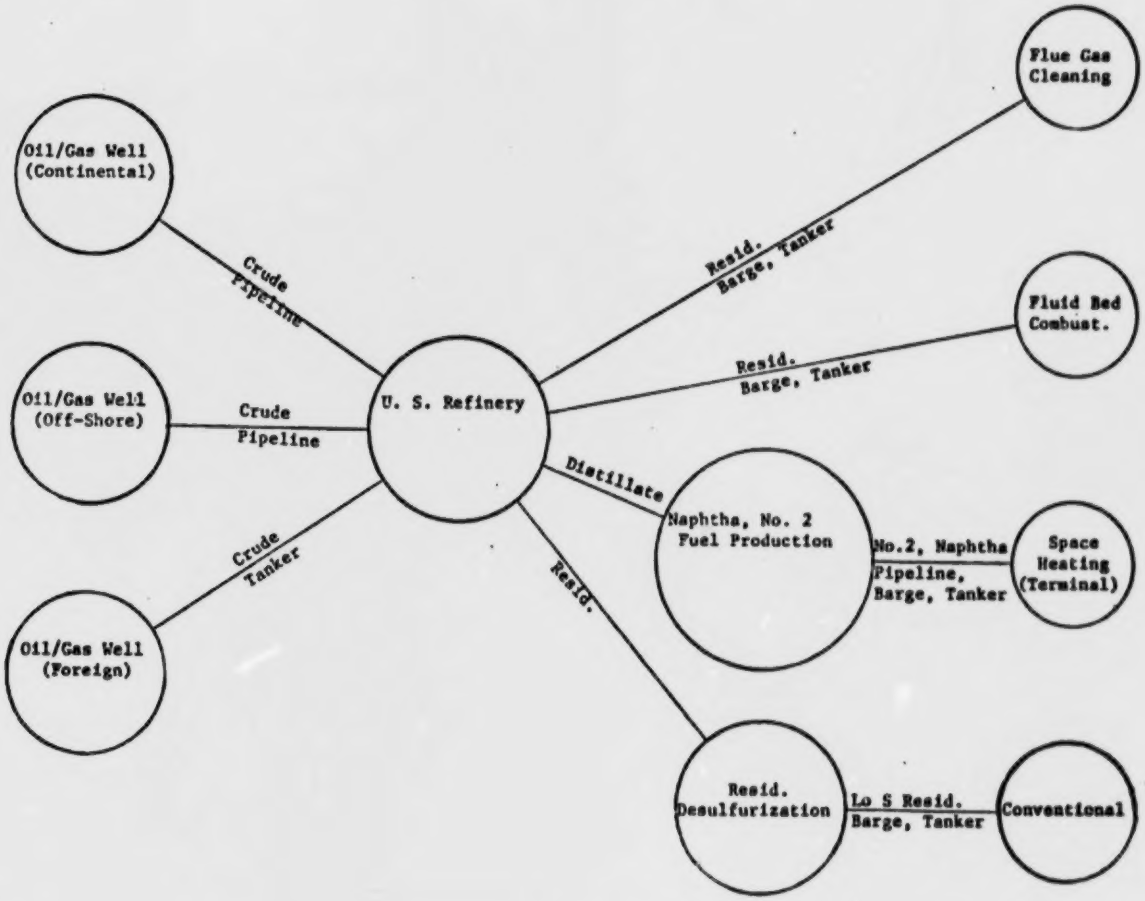
Oil/Gas Well (Continental)
Oil/Gas Well (Off-Shore)
Oil/Gas Well (Foreign)
Crude Pipeline
Crude Pipeline
Crude Tanker
U. S. Refinery
Resid. Barge, Tanker
Resid. Barge, Tanker
Distillate
Resid.
Flue Gas Cleaning
Fluid Bed Combust.
Naphtha, No. 2 Fuel Production
No.2, Naphtha Pipeline, Barge, Tanker
Space Heating (Terminal)
Resid. Desulfurization
Lo S Resid. Barge, Tanker
Conventional

FIGURE 3. SCHEMATIC REPRESENTATION OF MODULAR RELATIONSHIPS - OIL

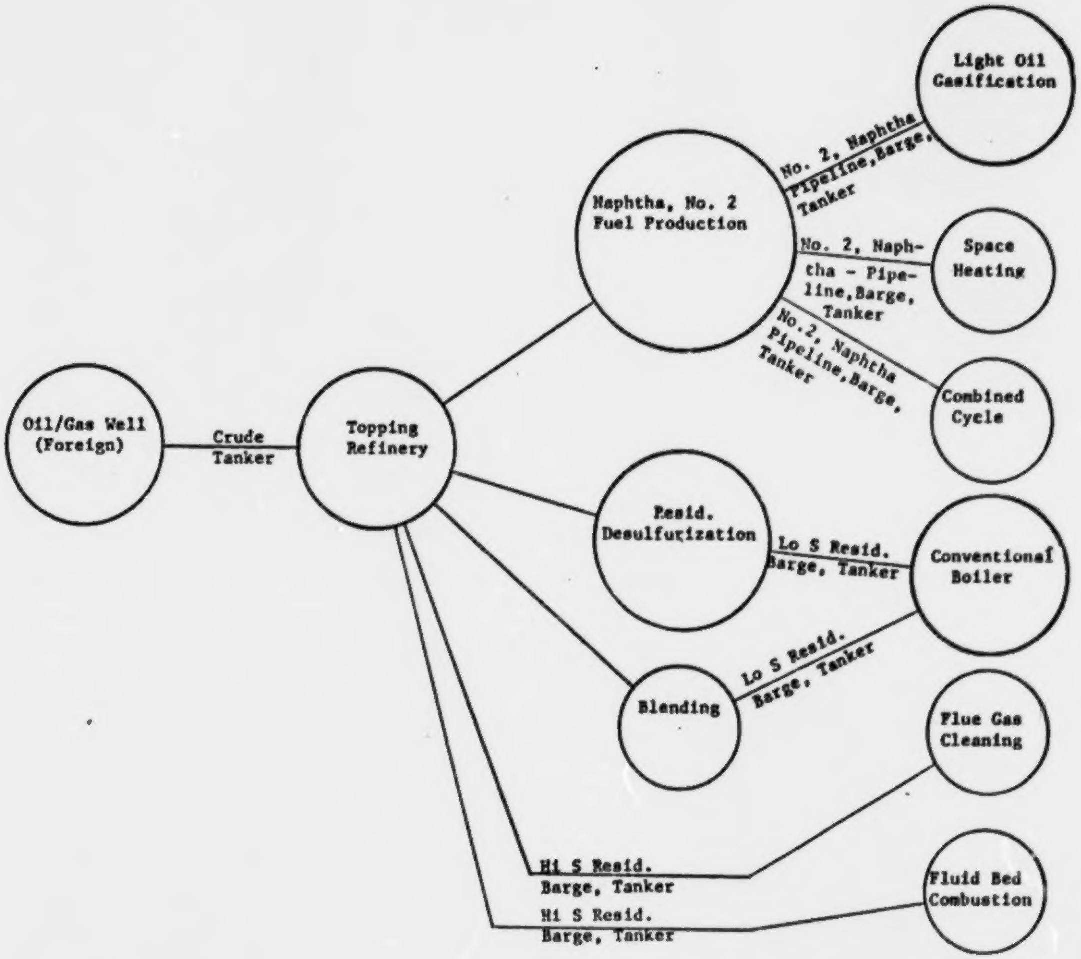
Oil/Gas Well (Foreign)
Crude Tanker
Topping Refinery
Naphtha, No. 2 Fuel Production
No. 2, Naphtha Pipeline, Barge, Tanker
Light Oil Gasification
No. 2, Naphtha - Pipeline, Barge, Tanker
Space Heating
No. 2, Naphtha Pipeline, Barge, Tanker
Combined Cycle
Resid. Desulfurization
Lo S Resid. Barge, Tanker
Conventional Boiler
Blending
Lo S Resid. Barge, Tanker
Flue Gas Cleaning
Hi S Resid. Barge, Tanker
Fluid Bed Combustion
Hi S Resid. Barge, Tanker

FIGURE 4. SCHEMATIC REPRESENTATION OF MODULAR RELATIONSHIPS - OIL, MODIFIED

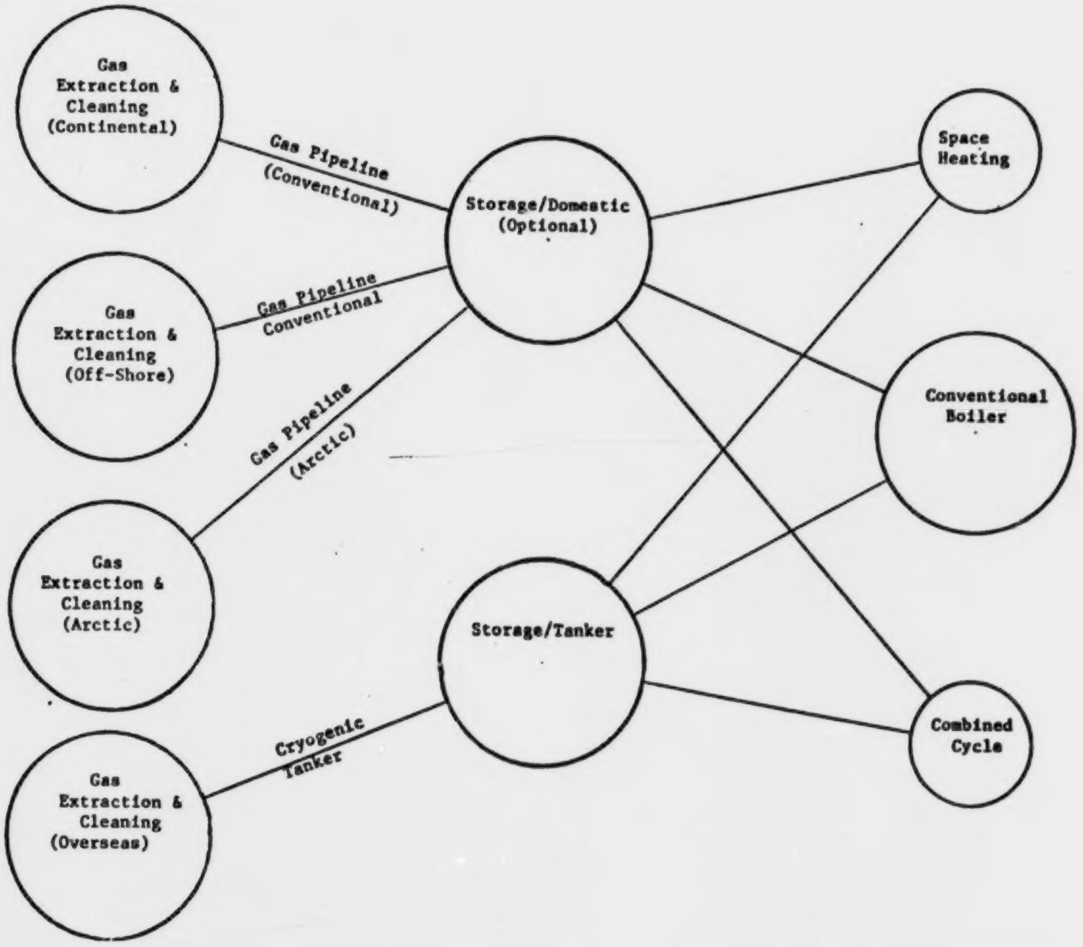
Gas Extraction & Cleaning (Continental)
Gas Extraction & Cleaning (Off-Shore)
Gas Extraction & Cleaning (Arctic)
Gas Extraction & Cleaning (Overseas)
Gas Pipeline (Conventional)
Gas Pipeline Conventional
Gas Pipeline (Arctic)
Cryogenic Tanker
Storage/Domestic (Optional)
Storage/Tanker
Space Heating
Conventional Boiler
Combined Cycle

FIGURE 5. SCHEMATIC REPRESENTATION OF MODULAR RELATIONSHIPS - GAS

TABLE 2. SUMMARY OF THE MORE IMPORTANT SYSTEMS OPTIONS

	Extraction Process	Transport	Processing of Raw Fuel	Secondary Processing	Transport & Storage	Utilization
			Fuel/Energy Systems - Coal			
(1) (2)	Surface Mine (Eastern Coal)	None	Physical Coal Cleaning	None	Rail, Barge	Conventional Boiler
(3)	Surface Mine (Eastern Coal)	None	Chemical Leaching	None	Slurry Pipeline	Conventional Boiler
(4)	Surface Mine (Eastern Coal)	None	Solvent Refining	None	None	Conventional Boiler
(5) (6) (7)	Surface Mine (Eastern Coal)	Rail, Barge, None	Gasify (Low Btu)	None	None	Conventional Boiler
(8) (9) (10)	Surface Mine (Eastern Coal)	Rail, Barge, None	Gasify (Low Btu)	None	None	Combined Cycle
(11) (12) (13)	Surface Mine (Eastern Coal)	Rail, Barge, None	Gasify (High Btu)	None	Pipeline Gas	Space Heating
(14) (15) (16)	Surface Mine (Eastern Coal)	Rail, Barge None	None	None	None	Conv. Boiler with Flue Gas Cleaning

TABLE 2. (Continued)

Extraction Process	Transport	Processing of Raw Fuel	Secondary Processing	Transport & Storage	Utilization
		Fuel/Energy Systems - Coal			
(17) (18) (19) Surface Mine (Eastern Coal)	Rail, Barge, None	None	None	None	Fluid Bed Combustion System
(20) through (38) Repeat above options with underground mined Eastern Coal					
(39) Surface Mine (Western Coal)	None	None	None	None	Conv. Boiler & Long Dist. Transmission
(40) Surface Mine (Western Coal)	Rail	None	None	None	Conventional Boiler
(41) Surface Mine (Western Coal)	None	Gasify (High Btu)	None	Pipeline Gas	Space Heating
(42) Surface Mine (Western Coal)	Rail	Gasify (Low Btu)	None	None	Conventional Boiler
		Fuel/Energy Systems - Oil			
(1) (2) Oil/Gas Well (Continental)	Oil Pipeline	U.S. Refinery	Resid. Desulf.	Barge, Tanker	Conventional Boiler

TABLE 2. (Continued)

Extraction Process	Transport	Processing of Raw Fuel	Secondary Processing	Transport & Storage	Utilization
		Fuel/Energy Systems - Oil			
(3) Oil/Gas Well (4) (Offshore)	Oil Pipeline	U.S. Refinery	Resid. Desulf.	Barge, Tanker	Conventional Boiler
(5) Oil/Gas Well (6) (Overseas)	Tanker	U.S. Refinery	Resid. Desulf.	Barge, Tanker	Conventional Boiler
(7) Oil/Gas Well (Continental) (8) (Off Shore)	Oil Pipeline	U.S. Refinery	No. 2 Oil	Pipeline	Space Heating
(9) Oil/Gas Well (Foreign)	Tanker	U.S. Refinery	No. 2 Oil	Pipeline	Space Heating
(10) Oil/Gas Well (11) (Continental) (Off Shore)	Oil Pipeline	U.S. Refinery	Resid. Desulf.	Barge, Tanker	Fluid Bed Combustion
(12) Oil/Gas Well (13) (Continental) (Off Shore)	Oil Pipeline	U.S. Refinery	Resid. Desulf.	Barge, Tanker,	Conv. Boiler with Flue Gas Cleaning
(14) Oil/Gas Well (15) (Foreign)	Tanker	U.S. Refinery	Resid. Desulf.	Barge, Tanker	Fluid Bed Combustion

TABLE 2. (Continued)

Extraction Process	Transport	Processing of Raw Fuel	Secondary Processing	Transport & Storage	Utilization
		Fuel/Energy Systems - Oil			
(16) Oil/Gas Well (17) (Foreign)	Tanker	Topping Refinery	No. 2 Oil	Barge, Tanker	Space Heating
(18) Oil/Gas Well (19) (Foreign)	Tanker	Topping Refinery	No. 2 Oil	Barge, Tanker	Combined Cycle
(20) Oil/Gas Well (Foreign)	Tanker	Topping Refinery	Light Oil Gasification	Gas Pipeline	Space Heating
(21) Oil/Gas Well (22) (Foreign)	Tanker	Topping Refinery	Naphtha Production	Barge, Tanker	Combined Cycle
(23) Oil/Gas Well (24) (Foreign)	Tanker	Topping Refinery	Resid. Desulf.	Barge, Tanker	Conventional Boiler
(25) Oil/Gas Well (26) (Foreign)	Tanker	Topping Refinery	Blending	Barge, Tanker	Conventional Boiler
(27) Oil/Gas Well (28) (Foreign)	Tanker	Topping Refinery	None - Hi S Resid.	Barge, Tanker	Conv. & Flue Gas Cleaning
(29) Oil/Gas Well (30) (Foreign)	Tanker	Topping Refinery	None - Hi S Resid.	Barge, Tanker	Fluid Bed Combustor
(31) Oil/Gas Well (Foreign)	Tanker	Topping Refinery	Heavy Oil Gasification	Gas Pipeline	Space Heating

TABLE 2. (Continued)

	Extraction Process	Transport	Processing of Raw Fuel	Secondary Processing	Transport & Storage	Utilization
			Fuel/Energy Systems - Gas			
(1) (2) (3)	Gas Well (Continental)	None	Desulfurization	None	Gas Pipeline	Conv. Boiler, Space Heating, Combined Cycle
(4) (5) (6)	Gas Well (Off Shore U. S.)	None	Desulfurization	None	Gas Pipeline	Conv. Boiler, Space Heating, Combined Cycle
(7) (8) (9)	Gas Well (Arctic)	None	Desulfurization	None	Arctic Gas Pipeline	Conv. Boiler, Space Heating, Combined Cycle
(10) (11) (12)	Gas Well (Overseas)	None	Desulfurization	None	Cryogenic Tanker & Stg.	Conv. Boiler Space Heating Combined Cycle

TABLE 3. SELECTED MODULES ANALYZED

Strip Mining of Eastern Coal
Strip Mining of Western Coal
Deep Mining of Coal
Physical Cleaning of Coal
Chemical Cleaning of Coal
Liquefaction of Coal (Solvent Refining)
Rail Transport of Coal
Conventional Boiler, Eastern Coal
Conventional Boiler, Western Coal
Conventional Boiler, Physically Cleaned Eastern Coal
Conventional Boiler, Chemically Cleaned Eastern Coal
Conventional Boiler, Liquefied Coal
Conventional Boiler (Limestone Scrubber), Eastern Coal
Conventional Boiler (MgO Scrubber), Eastern Coal
Conventional Boiler (Limestone Scrubber), Western Coal
Conventional Boiler (Limestone Scrubber), Physically Clean Eastern Coal
Gasification (Low Btu) Eastern Coal - Lurgi
Gasification (High Btu) Eastern Coal - Hygas
Gasification (High Btu) Lignite - CO_2 Acceptor
Gasification (Low Btu) Eastern Coal - Molten Iron Combustion
Gasification of Crude Oil
High Pressure Fluidized Bed
Chemically Active Fluidized Bed
Gas Well
Gas Desulfurization
Gas Pipeline
Conventional Boiler, Natural Gas
Underground Gas Storage
LNG Tanker
LNG Port Facilities
LNG Storage
LNG Distribution
LNG Gasification
Oil Shale Extraction and Processing
Oil/Gas Well - On Shore
Oil/Gas Well - Off Shore
Oil Tanker Transport
Oil Pipeline
Oil Barge
Refinery - Domestic Crude
Refinery - Imported Crude
Topping Refinery
Conventional Boiler, Domestic Residual
Conventional Boiler, Topping Residual
Municipal Refuse Processing (St. Louis Method)
Municipal Refuse Burning, Conventional Boiler, Limestone Scrubber
Space Heating - Electrical, gas, oil, coal and synthetic gas from coal
Nuclear Fission

energy system has been obtained as the summation of the estimated environmental burden for each module making up the system, modified by the efficiency of energy utilization for these modules. Weighting factors were applied to permit a summation of burdens.

In addition to the summation of environmental burdens, costs of energy conversion for each of the systems were estimated so that the systems could be compared economically, as well as environmentally. The cost of pollution control for specific modules is presented in the appropriate appendix for those modules for which this information is available. In addition, the overall cost of energy production has been derived for each system.

Derivation of Emission Values

The pollutant emissions resulting from the operation involved within each module were derived from various sources. These values were then reduced to a common basis, namely, emission per million Btu. This reference energy was taken as the heat value of the primary fuel produced by the module, except in the case of electric power generation, for which the input energy to the power plant was taken as reference. Thus, in general, the emissions are given in pounds per million Btu. The land use burden includes the land area involved and a time factor. For the processing and utilization modules the proper unit arises from the fact that a certain land area is associated with a plant with a stated throughput, say tons of coal per hour or the equivalent heating value (Btu per hour). When the area in acres is divided by this energy rate, the resulting units are acre-hour/10^6 Btu. For the extraction modules the area is associated with a total energy (e.g., tons of coal per acre). The resulting burden in acres/10^6 Btu is converted to consistent units by multiplying the burden by the length of time assumed for the operation.

DATA ANALYSIS

Environmental Burden of Modules

The unit-basis pollutant emissions, land-use burdens, and efficiencies, for 50 modules are compiled in a series of module data sheets which are presented in Appendix A. Data are included for those burdens for which information was available during the period of the study. Emission from processes which are in the early stages of development are estimates or are based on extrapolation from bench or pilot studies. Continued review of the data to incorporate new information as it is developed will be necessary in order for the modular approach to achieve its maximum potential in describing the overall burdens of fuel/energy systems.

The extensive data base represented by the tables presented in Appendix A can be summarized for the purpose of illustrating the information contained, by tabulating a few of the important environment parameters for some selected modules. These condensed data are given in Table 4. The values are stated in pounds per million Btu for air emissions of NO_x, SO_2, and particulates, for water emissions of suspended solids and organic materials, and for solid wastes produced. The land-use burden is expressed in acre-hour per million Btu. Data are given in Table 4 for selected gas, oil, and coal modules which include extraction, transportation, conversion or treatment, and utilization. The number of the table in Appendix A containing the complete data is indicated for each module.

The data presented in Table 4 illustrate the differences in burdens which exist among the various modules. These burdens arise through different steps in the fuel-energy cycle and various components of the environment can be affected. It is difficult to evaluate alternative energy systems directly on the basis of emissions data as presented in Table 4 or in Appendix A. Therefore, it was believed to be desirable to aggregate these complex emissions at various levels and finally into a single number which will reflect all of the emissions and thus aid in comparing the environmental aspects of various energy systems.

A method for accomplishing the aggregation of emissions was employed which is based upon methodology developed for the Bureau of Reclamation, U.S. Department of the Interior.(1) The details of the ranking methodology are given in Appendix B. During this brief study no attempt was made to detail the analysis on a regional basis. The results thus represent a national overview which can be useful in the evaluation of national priorities. Ultimate implementation of energy policy should include consideration of regional factors.

The first level of aggregation of the emission data, as described in Appendix B, is the summation of the weighted parameters for each environmental component within the module. The resulting totals for the air, water, solid, and land-use burdens are compiled for each module in Table 5. Since the actual emissions have been weighted in the calculation of the totals given, units are not assigned to the totals. Examination of Table 5 shows the range of values which occurs for a given type of burden. Some general points regarding control technology associated with the modules given in Table 5 should be noted.

- Mine modules assume land restoration (80 percent coverage, no bare areas greater than 1/4 acre, and 600 living stems per acre), and treatment of acid mine drainage

- Physical coal cleaning assumes restoration of land used for refuse piles (all pyritic material covered with nonreactive soil) and treatment of acid-bearing run-off

TABLE 4. SUMMARY OF PRINCIPAL ENVIRONMENTAL BURDENS FOR SOME SELECTED MODULES

		Selected Environmental Parameters							
		Air Emissions, lb/10^6 Btu			Water Emissions, lb/10^6 Btu		Solid Waste, lb/10^6 Btu		Land Use, acre-hour per 10^6 Btu
Selected Modules	Data From Table No.	NO_x	SO_2	Particulate	Suspended Solid	Organic	Ash	Sludge	
Extraction Modules									
Strip mining-Eastern (E.) coal	A-1	0.0002	Neg	0.14	0.55	Neg	0	0.24	0.3
Strip mining-Western (W.) coal	A-2	0.00008	Neg	0.07	0.28	Neg	0	0	0.16
Onshore oil well	A-34	8×10^{-6}	6×10^{-5}	3×10^{-6}	0	0.008	0	0	0.06
Natural gas well	A-24	0.23	Neg	Neg	0		0	0	0.06
Transportation Modules									
Rail-coal	A-7	0.02	0.0014	0.0014	Neg	Neg	0.083	Neg	0.29
Pipeline-oil	A-37	0.009	0.016	0.002	0	0	0	0	0.3
Pipeline-gas	A-26	0.304	0	0	0	0	0	0	1.0
Conversion or Treatment Modules									
Physical coal cleaning	A-4	0.006	0.004	0.01	Neg	Neg	0	0.3	0.003
Chemical coal cleaning	A-5	0.04	0.1	0.005	Neg	Neg	0	0	0.08
Solvent refining of coal	A-6	0.21	0.003	0.27	0	Neg	16.	0	0.08
Refining of oil-domestic crude	A-39	0.025	0.135	0.002	0.004	0.002	0	0.026	0.009
Natural gas desulfurization	A-25	0	0.0183	0	Neg	Neg	Neg	Neg	0.005
Utilization Modules									
Conventional boiler(CB)-W. coal	A-9	0.98	1.65	0.07	0.025	0.011	9.	0	0.1
C.B. with limestone scrubber (LSS)-W. coal	A-15	0.78	0.16	0.07	0.025	0.011	1.8	13.4	0.1
Fluidized-bed combustion plus combined cycle-E. coal	A-22	0.14	0.7	0.02	0	0	17.3	0	0.12
Gasification (molten iron combustion) plus C.B.-E. coal	A-20	0.39	0.017	0.034	0	0	10.	0	0.12
C.B. with MgO scrubber-E. coal	A-14	0.60	0.50	0.1	0.025	0.011	2.4	10.4	0.1
C.B.-physically cleaned E. coal	A-10	0.68	2.02	0.044	0.025	0.011	5.4	0	0.1
C.B. with LSS-physically cleaned E. coal	A-16	0.55	0.2	0.044	0.025	0.011	1.1	11.9	0.1
C.B.-chemically cleaned E. coal	A-11	0.75	1.93	0.1	0.025	0.011	11.9	0	0.1
C.B.-solvent refined E. coal	A-12	0.56	0.71	0.0003	0.025	0.011	0.031	0	0.09
Chemically active fluidized-bed plus combined cycle-residual oil	A-23	0.16	0.45	0.01	0	0	3.0	0	0.06
C.B.-residual oil from domestic crude	A-42	0.70	1.83	0.05	0	0	0	0	0.04
C.B.-natural gas	A-28	0.39	0.0006	0.015	0.016	0	0	0	0.02

TABLE 5. SUMMARY OF MODULE IMPACTS

Module Number	Module	Impacts, Weighted Sums (ΣW_pQ_p) for Each Environmental Component			
		Air	Water	Solid	Land Use
1	Eastern Coal, Strip Mine	0.186	0.0038	0.240	0.34
2	Western Coal, Strip Mine	0.0933	0.0013	0.040	0.17
3	Eastern Coal, Deep Mine	0.0005	0.045	9.60	0.20
4	Physical Cleaning of Coal	0.0218	0	0.06	0.003
5	Chemical Cleaning of Coal	0.212	0	0	0.002
6	Liquefaction of Coal (Solvent Refining)	0.222	0	16.0	0.027
7	Rail Transport of Coal	0.0247	0	0.083	0.29
8	Conv. Boiler, Eastern Coal	7.040	0.0039	12.0	0.10
9	Conv. Boiler, Western Coal	3.150	0.0039	9.0	0.13
10	Conv. Boiler, Physically Cleaned Eastern Coal	3.338	0.0039	5.41	0.10
11	Conv. Boiler, Chemically Cleaned Eastern Coal	4.215	0.0039	11.41	0.10
12	Conv. Boiler, Liquefied Coal	1.585	0.0039	0.074	0.09
13	Conv. Boiler, Limestone Scrubber, Eastern Coal	1.396	0.0039	29.8	0.10
14	Conv. Boiler, MgO Scrubber, Eastern Coal	1.394	0.0039	12.16	0.10
15	Conv. Boiler, Limestone Scrubber, Western Coal	1.453	0.0039	21.05	0.10
16	Conv. Boiler, Limestone Scrubber, Physically Cleaned Eastern Coal	0.922	0.0039	13.80	0.10

TABLE 5. (Continued)

Module Number	Module	Impacts, Weighted Sums ($\Sigma W_p Q_p$) for Each Environmental Component			
		Air	Water	Solid	Land Use
17	Gasification. Eastern Coal, Lurgi (Low Btu) plus Conv. Boiler	1.624	0.0046	9.75	0.12
18	Gasification, Eastern Coal, Hygas (High Btu)	1.79	0.0023	31.9	0.02
19	Gasification, Lignite, CO_2 Acceptor (High Btu)	0.027	0.0023	39.2	0.02
20	Gasification, Eastern Coal, Molten Iron Combustion (Low Btu) plus C. B.	0.449	0	10.0	0.12
21	Gasification of Crude Oil	0.17	0.0002	0.18	0.04
22	High Pressure Fluidized Bed plus C. C.	1.042	0	17.40	0.10
23	Chemically Active Fluidized Bed plus C. C.	0.761	0	3.0	0.12
24	Natural Gas Well	0.845	0.0031	0	0.05
25	Natural Gas Desulfurization	0.0229	0	0	0.005
26	Gas Pipeline	0.304	0	0	1.00
27	Underground Gas Storage	0.60	0	0	Neg.
28	Conv. Boiler, Natural Gas	0.446	0.0002	0	0.02
29	LNG Tanker	0	0	0	0
30	LNG Port Facilities	0	0	0	Neg.
31	LNG Storage	0	0	0	0.00005
32	LNG Gasification	0.0026	0	0	0.00004
33	Oil Shale Extraction and Processing	0.484	0.001	>400	N.D.

TABLE 5. (Continued)

Module Number	Module	Impacts, Weighted Sums (ΣW_pQ_p) for Each Environmental Component			
		Air	Water	Solid	Land Use
34	Oil/Gas Well - On Shore	0.00008	0.0223	0	0.05
35	Oil/Gas Well - Off Shore	0.00016	0.0023	0	0.05
36	Oil Tanker Transport	0.1416	0.0495	0	0
37	Oil Pipeline	0.157	0.00495	0	0.31
38	Oil Barge	0.0143	0.00512	0	0
39	Refinery, Domestic Crude	0.214	0.0068	0.026	0.009
40	Refinery, Imported (Arabic) Crude	0.225	0.0068	0.026	0.009
41	Topping Refinery	0.155	0.00425	0.026	0.009
42	Conv. Boiler, Domestic Resid	3.161	0	0	0.04
43	Conv. Boiler, Topping Resid	1.811	0	0	0.04
44	Municipal Refuse Processing (St. Louis, Method)	0	0	0	0.034
45	Municipal Refuse Burning, Conv. Boiler, Limestone Scrubbing	0.717	0	-132.0	0.1
46	Space Heating, Electricity	0	0	0	0
47	Space Heating, Gas	0.572	0	0	0
48	Space Heating, Oil	1.13	0	0	0
49	Space Heating, Coal	10.5	0	0	0
50	Nuclear Fission	0.0032	0.022	4.0	0.3

- Boiler modules assume 99 percent efficiency for particulate removal
- Stack gas cleaning modules assume 90 percent reduction in SO_2 and 20 percent reduction in NO_x
- Cooling towers are assumed for all modules discharging heat in water effluents. The heat discharged to air is not included in the burden totals.

The compilation of Table 5 also shows the cross-media effects of alternate pollution control approaches. For example, Modules 8 through 16 are all conventional boilers burning several different kinds of coal, either with or without stack-gas cleaning. Comparison of Module 8 with Module 13 shows an 80 percent reduction in air burden when a limestone scrubbing system is employed, with an attendant increase in solid burden due to the gypsum sludge produced. Module 14 shows the same reduction in air burden, but does not have the increase in solid waste, since the MgO scrubber is a regenerative system. Module 22, high-pressure fluidized-bed combustion, also is a coal utilization module which exhibits yet smaller air burden with an intermediate solid impact.

Thus, Table 5 can be used to compare alternative processes on a burden-by-burden basis.

Environmental Burden of Systems

The second level of aggregation of the emission data--as described in Appendix B--is the summation of the weighted totals for each environmental component over all of the modules in each chosen system. Again weighting factors reflecting the relative importance of each module are employed in the summation. The result is a separate total for air, water, solid waste, and land-use burdens which reflect the individual contributions of all of the burdens.

The final aggregation of the emission data is the summation of the environmental component totals to give a single system environmental index. The methodology which was used in the derivation of this final aggregation is described in detail in Appendix B. The results obtained by this approach are described in the following paragraphs. It should be noted that this is simply one method of aggregating the complex emission data and the results are not a unique representation of that data. The method includes the flexibility to allow any system evaluator to select weighting factors at each level of aggregation to reflect his understanding of the relative importance of each factor involved. The computer program readily allows recalculation of the system environmental indices on the basis of refined weighting factors.

During this short study a group of 26 systems for producing electric power and a group of 5 systems for space heating were selected for analysis. The electric power group included 15 coal, 2 mixed-fuel (coal plus municipal refuse), 6 oil, 1 nuclear fission, and 2 natural gas systems. These include the important options which must be considered in arriving at an energy policy. The group of space heating systems included electricity, natural gas, oil and coal.

Electric Power Systems

All of the systems which have been analyzed are listed in Table 6. For each electric power system and appropriate modules, burdens given in Table 5 were employed to derive an overall system environmental index. Since the module burdens are stated on a unit basis, the efficiencies must be factored in. The weighted sums in each module were first adjusted by dividing each of the four values by the product of the efficiencies of each module following it in the system sequence. The impacts for electric-power-generation modules are stated on a unit input basis, therefore, the efficiency factor is applied to those impacts as well, in order to put all systems on a common output basis. The adjusted burdens of all modules in a given system were then added to give total air, water, solid and land-use burdens. These totals are given for each system in Table 6. Again, the burden data in Table 6 are useful in comparing the trade-offs which are involved in the consideration of various system options.

The total air, water, solid and land use values were normalized as described in Appendix B and then summed to give the overall system environmental index. The systems are arranged in ranked order in Table 6 according to the value of the derived system index.

Three additional elements are included in Table 6; the overall system efficiency (the product of the efficiencies of each module in the system), the estimated overall cost to produce electricity, and the approximate year of availability of each system.

It should be emphasized that the system index as given in Table 6 was derived with equal weight being given to the burdens from each module in the system and also to the air, water, solid and land use burdens. With these assumptions, three of the four systems which include limestone scrubbing are ranked below the corresponding system without scrubbing. This occurs because the SO_2 and sludge produced (16 lb sludge per lb of SO_2 removed) are given equal environmental importance. In view of the fact that air emissions are, in general, more likely to produce adverse health effects than are solid wastes, it would be reasonable to assign a lesser weight to solid waste in the system analysis. Based on this premise a second calculation was carried out in which the solid burdens were assigned a weighting factor of 0.3 while keeping the remaining media weights equal to unity. The results of this calculation are given in Table 7 in which the systems are ordered according to their revised ranking. For comparison, the rank of each system obtained previously with equal media weights also is given. The revised order shows the expected changes. Systems with

TABLE 6. SUMMARY OF RANKED SYSTEMS, WITH MEDIA IMPACTS, EFFICIENCIES, AND COSTS

(Weighting Factors for Air, Water, Solid, and Land Uses = 1)

Rank	System Environ. Index	System					Total Air Impact	Total Water Impact	Total Solid Impact	Total Land Impact	Overall System Eff.	Overall* Cost, mills/kwh	Est. Year of Application
		Extraction	Transportation	Processing	Transportation	Utilization							
1	1.5	None	LNG Tanker/Storage/Distribution/Gasification			Conv. boiler	1.21	0.0004	0	0.054	.323		Current
2	5.2	None	Imported resid	Fl. bed combust.		Combined cycle	2.00	0	7.89	0.315	.380	11.3	1985
3	11.2	80% E. coal-20% Prepared Mun. Refuse				Conv. boiler lime scrub	4.08	0.018	-6.58	1.75	.348	11.5	1975
4	12.4	Nuclear Fission - Total System**					0.0032	0.022	4.	0.3	.300	11.0	Current
5	16.7	Nat. gas well		Desulf. nat. gas	Nat. gas pipeline	Conv. boiler	4.47	0.0092	0	2.91	.341	9.1	Current
6	19.7	East coal, S.M.	Rail	Gasify, low Btu molt. iron combust.	None	Conv. boiler	2.00	0.0115	31.28	2.27	.329		1985
7	22.6	West coal, S.M.	Rail	None	None	Conv. boiler	8.83	0.0140	24.66	1.59	.369	11.5	Current
8	23.3	East coal, S.M.	Rail	Fl. bed combust.	None	Combined cycle	3.00	0.0100	46.64	1.92	.378	10.8	1985
9	23.7	90% E. coal-10% Prepared Mun. Refuse				Conv. boiler lime scrub	4.34	0.02	39.7	1.92	.348	11.5	1975
10	23.9	East coal, S.M.	Rail	None	None	Conv. boiler MgO scrub	4.59	0.0220	35.67	2.09	.349	11.5	1980
11	24.6	None	Oil tanker	Topping refinery	Oil barge	Conv. boiler topp. resid.	5.75	0.163	0.0703	0.132	.324		1975
12	24.6	East coal	Rail	Physical coal clean	None	Conv. boiler	9.73	0.0221	15.76	2.21	.324	10.0	Current
13	25.0	East coal	Rail	Physical coal clean	None	Conv. boiler lime scrub	3.38	0.0234	40.65	2.34	.307	12.4	1975
14	27.1	West coal, S.M.	Rail	None	None	Conv. boiler lime scrub	4.49	0.0148	60.49	1.58	.349	13.3	1975
15	27.5	Oil well, onshore	Oil pipeline	Refinery domestic	Oil barge	Conv. boiler dom. resid.	9.64	0.1165	0.0703	1.24	.332	11.2	Current
16	29.3	East coal, S.M.	Rail	Coal liquefaction	None	Conv. boiler	5.64	0.0242	44.61	2.58	.276	13.2	1985
17	30.7	East coal, S.M.	Rail	Chemical coal clean	None	Conv. boiler	12.57	0.0213	31.76	2.07	.350	10.5	1980
18	30.8	Oil well, onshore	Oil pipeline	Crude oil gasification	Nat. gas pipeline	Conv. boiler	3.09	0.1016	0.507	4.20	.270		1980
19	33.2	East coal, S.M.	Rail	Gasif. low Btu Lurgi.	None	Conv. boiler	7.49	0.0342	41.11	3.06	.244		1985
20	34.4	Oil well, off-shore	Oil pipeline	Refinery domestic	Oil tanker	Conv. boiler dom. resid.	9.99	0.174	0.071	1.25	.321	11.2	Current
21	36.3	East coal, S.M.	Rail	None	None	Conv. boiler lime scrub	4.59	0.0221	86.0	2.09	.348	11.5	1975
22	37.7	East coal, S.M.	Rail	None	None	Conv. boiler	19.6	0.0207	33.31	1.97	.369	9.1	Current
23	41.3	Oil well, onshore	Oil pipeline	Refinery domestic	Oil tanker	Conv. boiler dom. resid.	9.99	0.237	0.071	1.25	.321	11.2	Current
24	43.6	East coal, D.M.	Rail	Physical coal clean	None	Conv. boiler	9.16	0.148	44.49	1.78	.324	10.0	Current
25	45.1	East coal, D.M.	Rail	Physical coal clean	None	Conv. boiler lime scrub	2.78	0.157	71.04	1.89	.307	12.4	1975
26	53.3	East coal, D.M.	Rail	None	None	Conv. boiler	19.09	0.1216	58.60	1.59	.369	9.1	Current

* Approximate-system costs may vary by ± 2.5 mills/kWhr for specific cases.

** Includes only environmental impacts resulting from normal controlled operation at this time. Analysis of nuclear accident probability and effect is not complete.

TABLE 7. ALTERNATE RANKING OF SYSTEMS

Weighting Factor for Solid Waste = 0.3
Weighting Factors for Air, Water, and Land Use = 1

Rank for W_s = 0.3	System Environmental Index	Rank for All W_n = 1	System				
			Extraction	Transportation	Processing	Transportation	Utilization
1	1.5	1	None	LNG/Tanker/Storage/Distribution/Gasification			Conv. boiler
2	3.8	2	None	Imported resid	Fl. bed combust.		Combined cycle
3	12.2	4	Nuclear Fission - Total System*				
4	12.3	3	80% E. coal-20% Prepared Mun. Refuse				Conv. boiler lime scrub
5	14.4	6	East coal, S.M.	Rail	Gasify, low Btu mult. iron combust.	None	Conv. boiler
6	15.3	8	East coal, S.M.	Rail	Fl. bed combust.	None	Combined cycle
7	16.7	5	Nat. gas well		Desulf. nat. gas	Nat. gas pipeline	Conv. boiler
8	16.7	14	West coal, S.M.	Rail	None	None	Conv. boiler lime scrub
9	16.9	9	90% E. coal-10% Prepared Mun. Refuse				Conv. boiler lime scrub
10	17.7	10	East coal, S.M.	Rail	None	None	Conv. boiler MgO scrub
11	18.0	13	East coal	Rail	Physical coal clean	None	Conv. boiler lime scrub
12	18.4	7	West coal, S.M.	Rail	None	None	Conv. boiler
13	21.5	21	East coal, D.M.	Rail	None	None	Conv. boiler lime scrub
14	21.6	16	East coal, S.M.	Rail	Coal liquefaction	None	Conv. boiler
15	21.9	12	East coal	Rail	Physical coal clean	None	Conv. boiler
16	24.5	11	None	Oil tanker	Topping refinery	Oil barge	Conv. boiler topp. resid.
17	25.3	17	East coal, S.M.	Rail	Chemical coal clean	None	Conv. boiler
18	26.2	19	East coal, S.M.	Rail	Gasif. low Btu Lurgi.	None	Conv. boiler
19	27.5	15	Oil well, onshore	Oil pipeline	Refinery domestic	Oil barge	Conv. boiler dom. resid.
20	30.7	18	Oil well, onshore	Oil pipeline	Crude oil gasification	Nat. gas pipeline	Conv. boiler
21	32.0	22	East coal, S.M.	Rail	None	None	Conv. boiler
22	32.9	25	East coal, D.M.	Rail	Physical coal clean	None	Conv. boiler lime scrub
23	34.4	20	Oil well, offshore	Oil pipeline	Refinery domestic	Oil tanker	Conv. boiler dom. resid.
24	35.9	24	East coal, D.M.	Rail	Physical coal clean	None	Conv. boiler
25	41.3	23	Oil well, onshore	Oil pipeline	Refinery domestic	Oil tanker	Conv. boiler dom. resid.
26	43.2	26	East coal, D.M.	Rail	None	None	Conv. boiler

* Includes only environmental impacts resulting from normal controlled operation at this time. Analysis of nuclear accident probability and effect is not complete.

relatively large solid burdens moved up in rank. For example, the systems which include limestone scrubbing are ranked above the corresponding systems without scrubbing.

Space Heating Systems

A separate analysis was made of a group of 5 space heating systems which represent a utilization of energy one step beyond the generation of electricity. The methodology was the same as before with appropriate modules chosen to make up the representative systems, and the module data given in Table 5 used to derive the system index. The results are given in Table 8 in which the space heating systems are ranked according to the system index.

The oil, coal, and synthetic gas systems are grouped in the ranking between gas, the highest, and electricity, the lowest. The low ranking of the electrical space heating system reflects the inefficiency of the electric power generation module.

DISCUSSION OF THE RESULTS

Systems Relationships

Inspection of Tables 6 and 7 reveals a number of interesting features. A few of these may be noted as illustrative of the comparisons which may be drawn.

- Natural gas and LNG systems predictably rank high environmentally.
- Among the currently available systems, nuclear fission, Western coal, and imported oil/topping refinery systems are highly ranked.
- MgO scrubbing systems and, given the assumption of lesser weight for solid waste, limestone scrubbing systems are favorably ranked.
- Various coal cleaning and processing options show significant environmental gains over the use of untreated coal.
- The developmental technologies; chemically-active fluidized-bed combustion of oil, molten iron gasification of coal, and high-pressure fluidized-bed combustion of coal are highly promising from the environmental viewpoint.
- Systems including strip mining of coal are environmentally acceptable if land restoration and treatment of acid mine drainage is practiced.

TABLE 8. SUMMARY OF RANKED SPACE HEATING SYSTEMS

Rank	System Environmental Index	Fuel for Space Heating	Total Air Burden	Total Water Burden	Total Solid Burden	Total Land Burden
1	8.3	Natural gas[a]	2.3	0.005	0	1.5
2	16.1	Fuel oil, 0.3% sulfur[b]	1.7	0.054	0.037	0.6
3	17.9	Coal, 1.5% sulfur[c]	11.0	0.009	0.85	1.4
4	19.7	Synthetic gas from coal[d]	3.6	0.012	46.3	1.4
5	30.8	Electricity[e]	4.6	0.022	74.6	2.1

(a) System comprising: gas well, gas desulfurization, gas pipeline, gas space heating.

(b) System comprising: on-shore oil well, oil pipeline, domestic refinery, fuel oil space heating.

(c) System comprising: S.M.E. coal, rail transport, physical coal cleaning, coal space heating.

(d) System comprising: S.M.E. coal, rail, high Btu gasification (HYGAS), gas space heating.

(e) System comprising: S.M.E. coal, rail, conv. boiler with limestone scrubbing, electrical space heating.

- The oil systems are intermediate in rank due to higher than average air and water emissions.

One of the most striking results is the high ranking of the coal/municipal refuse, mixed-fuel systems. This option, described in Appendix U, is highly promising from a number of viewpoints. The modules (processing and burning of municipal refuse) are based on the St. Louis approach (arbitrarily selected for illustration), and the system burdens were derived by combining the appropriate fraction of the burdens from the modules involved. This option consumes the combustible portion of the municipal refuse which obviates the need for an alternate means of disposal and, in turn, results in a negative value (a credit) for the solid waste burden of the module. In addition, the prepared refuse replaces a portion, 10 to 20 percent in the cases included, of the coal required by the power plant, thus reducing the coal system burden by that fraction.

A system involving shale oil was not included in the computer analysis. With the current understanding of the approaches to the exploitation of shale oil,(2,3,4) it appears that undesirably large environmental impacts will be associated as indicated in the data for the shale oil module in Table 5. These impacts will certainly place any system including the shale oil module at the bottom of the ranked list. Therefore, it was excluded from the analysis of the rest of the systems so as to avoid distorting the calculations.

Systems Availability

An approximate picture of the estimated availability time frame may be drawn by listing the systems as follows:

(1) Currently available
    LNG
    Nuclear fission
    Natural gas
    Oil-conventional boiler
    Coal-physical cleaning

(2) Available by 1975
    Mixed fuel--coal/municipal refuse
    Topping of imported crude
    Limestone scrubbing of flue gas

(3) Available by 1980
    MgO scrubbing of flue gas
    Chemical coal cleaning
    Crude oil gasification

(4) Available by 1985

Fluidized-bed combustion of coal and oil
Gasification of coal
Liquefaction of coal (solvent refining).

Cost of Pollution Control

The costs associated with the various mechanisms for the control of emissions from different phases in the fuel/energy cycle are developed in the pertinent appendices. A summary of the ranges of control costs in terms of medium, fuel, and module is given in Table 9.

TABLE 9. SUMMARY OF CONTROL COSTS

Medium		Control Cost per 10^6 Btu	Module
Air			
Coal		\$0.10 - \$0.35	Processing, power plant
Gas		0.01 - 0.05	Extraction, power plant
Oil		0.05 - 0.25	Processing, power plant
	Total	\$0.16 - \$0.65	
Water			
Coal		\$0.005 - \$0.01	Extraction
Gas		0.005 -	Extraction
Oil		0.005 - 0.01	Extraction, processing
	Total	\$0.015 - \$0.02	
Solid			
Coal		\$0.01 - \$0.10	Extraction, processing, power plant
Gas		0 - 0	
Oil		0 - 0.03	Processing
	Total	\$0.01 - \$0.13	

SECTION V

NUCLEAR FISSION ENERGY SYSTEMS

The alternate energy supplies considered commercially viable in the 1972 to 1990 time period included the fossil fuels and nuclear fission. Power generation by means of nuclear fission is expected to expand during the time period under consideration and thus to supply an increasing share of the nation's energy demand. It is necessary, therefore, to consider the environmental impacts associated with the entire range of operations of the nuclear power industry.

There are currently five fission power plant concepts being developed. These are:

- Light Water Reactor (LWR)
- High-Temperature Gas-Cooled Reactor (HTGR)
- Liquid Metal Fast Breeder Reactor (LMFBR)
- Gas-Cooled Breeder Reactor (GCBR)
- Molten-Salt Breeder Reactor (MSBR).

The LWR and the HTGR are commercially viable, in that they are commercially available to the electric power industry. With the national commitment to developing the LMFBR, it is expected that this type of power plant will be commercially applied in the latter part of this time period. The GCBR and the MSBR are being developed as backup technologies for the nuclear power industry and are not expected to reach commercial application in the 1975 to 1990 time period. Therefore, these two concepts are not included in this assessment; rather they are treated with the analyses of advanced energy technologies and are reported in Appendix W of this report.

All forecasts made to date show continued increases in the amount of electricity consumed in the United States over this time period and in the number of nuclear power plants built to supply that electricity. If these forecasts hold true, then there will be a corresponding increase in the amount of radionuclides generated in meeting this electrical demand. The amount of radionuclides released to the environment also is expected to increase even though improved radwaste systems are adopted which would reduce the release rates. This study forecasts the quantity of radionuclides released during 1975, 1980, 1985, and 1990.

The quantities of radionuclide wastes from the LWR power reactor industry for 1967, 1970, 1975, and 1980 were previously forecast in Phase I

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of a study(5) conducted for the U. S. Atomic Energy Commission. The forecast of this document is based on the same general assumptions with some modifications of input data and can be considered a continuation of that forecast.

TECHNICAL APPROACH

A combination of forecast data for the electrical power industry and general material balances for the nuclear segment of that industry are used to estimate the quantities of waste for 1975, 1980, 1985, and 1990. The relevant material flows in and out of the nuclear power industry are identified and quantified by type and location, with emphasis placed on determining the final disposition of waste materials.

The general flow of radioactive materials through the power reactor system was divided into 9 steps for the uranium cycle and 8 steps for the thorium cycle. These 17 steps are presented schematically in Figure 6. For each step, a material balance was made to determine relevant inputs and outputs, including the quantities, physical forms, and disposal system. The material balances for each process are presented in flowcharts and tables. Five of the steps involved two distinctly different processes having different effluents and, thus, two sets of data were prepared. (As an example, separate tables were prepared for the acid leach and carbonate leach uranium mills activities.) The waste burial steps for the uranium and thorium cycles were combined. Each of the resultant steps is described as a separate industry and the data for each is presented in Appendix V of this report.

The waste produced by each process was assumed to be directly proportional to the activity level throughputs for 1967 and 1970 and are taken from AEC records and Nuclear Industry 1970. Projections were made using the Linear Programming Model of the U. S. Power Economy(6) which has been used in previous studies for the USAEC,(7) and the ISOPRO computer code(8) which calculates throughputs based on installed capacity.

Assumptions Made in This Study

Because this was a preliminary study, several simplifying assumptions were made which are listed here.

- The AEC is now providing numerical guidelines on design objectives for light water cooled reactors which would carry out its policy of keeping radioactivity in effluents to levels which are as low as practicable. The cited projected levels for reactors built after

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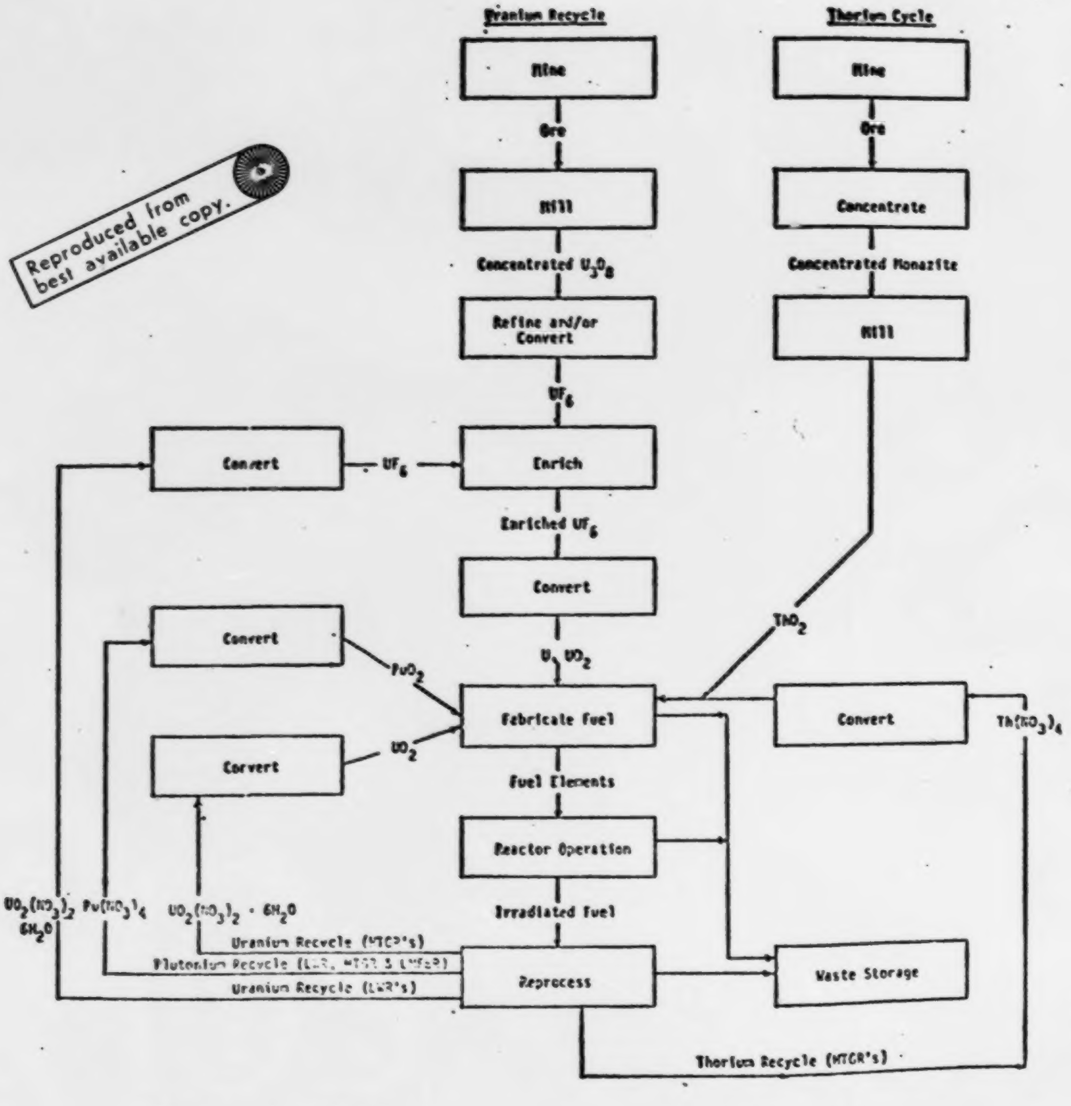
Uranium Recycle
Thorium Cycle
Mine
Ore
Mill
Concentrated U_3O_8
Refine and/or Convert
UF_6
Mine
Ore
Concentrate
Concentrated Monazite
Mill
Convert
UF_6
Enrich
Enriched UF_6
Convert
U, UO_2
ThO_2
Convert
PuO_2
Convert
UO_2
Fabricate Fuel
Convert
$Th(NO_3)_4$
Fuel Elements
Reactor Operation
Irradiated Fuel
$UO_2(NO_3)_2$ $6H_2O$
$Pu(NO_3)_4$
$UO_2(NO_3)_2 \cdot 6H_2O$
Uranium Recycle (HTGR's)
Plutonium Recycle (LWR, HTGR & LMFBR)
Uranium Recycle (LWR's)
Reprocess
Waste Storage
Thorium Recycle (HTGR's)

FIGURE 6. MATERIAL FLOW IN NUCLEAR (FISSION) FUEL CYCLE

1980 reflect anticipated technological improvements in radwaste treatments.

- It is anticipated that numerical guidelines also will be forthcoming on design objectives for fuel reprocessing plants to keep their radiation releases and resultant radiation exposure as low as practicable. The projected levels reflect some anticipated technological improvements in waste treatment systems for power and reprocessing plants.

- The quantities quoted for radiological impact in this report are given as total activity (curies) released. The effects of these releases, which depend on the particular nuclides involved, are excluded in this study. Similarly, the occupational hazards are excluded.

- No attempt was made to anticipate any changes in the standards or estimate any costs that might be involved in meeting them.

- The primary assumptions applying to two or more processes are:

(1) The study covers only the commercial nuclear power industry, including all related portions of the fuel cycle.

(2) Only LWR's, HTGR's, and LMFBR's were included in the study.

(3) LWR's and LMFBR's operate only in the uranium fuel cycle. Plutonium recycle was included. HTGR's operate only on the thorium cycle. Oxide fuels are used for all reactors.

(4) Only gaseous diffusion enrichment facilities are used assuming a tails assay of 0.2 percent U^{235}.

(5) No target irradiations were considered, or the recovery of special products (i.e., Np^{237}, Cs^{137}).

(6) The physical limits of the power reactor system for each type of waste and product are as follows:

Type of Waste or Product	System Physical Limit
Airborne	Physical boundary of plants
Waterborne	Physical boundary of plants
Surface-stored wastes	Physical boundary of plants
Burial wastes	Burial ground
Production	Shipping facilities

(7) The radwaste treatment systems used in this study reflect anticipated technological improvements in power reactor radwaste systems.

(8) Activation of permanent reactor equipment was not determined. No waste disposal due to decommissioning of reactors and reprocessing plants is included.

(9) Possible accidental releases of radioisotopes during shipments were not included.

(10) Solidified high-level wastes are to be shipped to permanent storage five years after reprocessing.

(11) The use and disposal of radioisotopes for research and medical applications were not included.

(12) Available economic and technical data were used. Special analyses were not made to develop new data. 1970 costs were used for operating and capital costs.

(13) No throughput for foreign use is included.

Because information was not readily available in the short time permitted for this report, capital and operating costs were not developed for many of the waste treatment systems used in the nuclear industry. General systems for which no cost data were developed were: sanitary wastes, nonradioactive solid wastes, and nonradioactive chemicals discharged to the air, land, and water. The reason is that the costs for such systems are small in relation to the total costs of waste treatment systems. The components of the nuclear industry for which no costs were developed are as follows:

Industry Component	Waste System
U Mining	Mine Ventilation Systems Low-grade Ore Disposal
U Milling	Ventilation Systems Tailings Disposal
Th Milling	Solid and Liquid Wastes
Enrichment	Airborne Wastes Liquid-borne Wastes
Surface Burial	Capital Costs

The radiological releases at these stages of the nuclear fuel cycle are small in comparison to those at the fabrication, reactor operation, and reprocessing stages.

SUMMARY

Estimates have been made of the quantity of effluent expected from the projected utilization of nuclear power reactor plants to meet the electrical energy demand during the period 1975-1990. These estimates are made assuming normal plant operating conditions. On the basis of the time allotted for completing the study, the emphasis was placed upon identifying and quantifying the release of radiological effluents in the nuclear fuel cycle. A very preliminary study was made of some of the other effluents of importance and these are also reported.

Nuclear Demand and Fuel Requirements

Using historical data from 1965 to the present a constant growth rate of 7.18 percent was used for projecting electrical demand up to 1980. Using a mix of other data and other energy projections, growth rates of 6.6 percent per year and 5.6 percent per year were used for the decades 1980-1990 and 1990-2000, respectively. To project the nuclear requirements, it was assumed that the nuclear plants would be base load plants with fossil plants built after 1980 being used for load following. Further, it was assumed that no fossil plants would be built after 1990. Based upon these assumptions, nuclear plants will produce roughly 19/29/41/54 percent of the total installed capacity for the years 1975/1980/1985/1990. If construction schedules for nuclear plants continue to slip and/or no major new markets for electricity appear in this time period, these demand values may be considered upper estimates. These estimates of nuclear power requirements were used to define the nuclear fuel requirements and the throughputs for each stage of the nuclear fuel cycle.

Environmental Emissions

Estimates of the quantity of radioisotopes released to air, water, and land receptors were made using the calculated throughputs required to meet the demand schedule for each stage of the nuclear fuel cycle. These are summarized in Tables 10, 11, and 12 for air, water, and land receptors, respectively. Also shown in the tables are the other burdens which must be studied to determine the total environmental impact. Where data on these nonradiological burdens were immediately available, they are included in Tables 10 to 12.

Throughout this report the amounts of radioactive wastes are reported as curies of radioactivity. However, the total number of curies should not be interpreted as a measure of the radiation hazard presented by

TABLE 10. SUMMARY OF ENVIRONMENTAL IMPACTS--AIR RECEPTORS

Stage of Cycle	Parameter	Year			
		1975	1980	1985	1990
U Mining	Radiological, Ci(a)				
	Particulate & Gas				
	Thermal				
U Milling	Radiological, Ci	5,000	9,000	16,000	25,000
	Particulate & Gas				
	Thermal				
Th Mining & Milling	Radiological, Ci	0	0	0	0
	Particulate & Gas				
	Thermal				
U Conversion	Radiological, Ci	0	0	0	0
	Particulate & Gas				
	Thermal				
U Enrichment	Radiological, Ci	.3	.5	.8	1.3
	Particulate & Gas				
	Thermal				
Fuel Fabrication	Radiological, Ci	.56	.86	1.41	2.79
	Particulate & Gas				
	Thermal				
Reactor Operation	Radiological, Ci	$9.4\text{x}10^6$	$2.0\text{x}10^7$	$2.4\text{x}10^7$	$2.9\text{x}10^7$
	Particulate & Gas				
	Thermal	32(b)	100	253	504
Fuel Reprocessing	Radiological, Ci	$1.0\text{x}10^7$	$1.7\text{x}10^7$	$1.9\text{x}10^7$	$2.2\text{x}10^7$
	Particulate & Gas				
	Thermal	25(c)	62	100	190
Conversion	Radiological, Ci	Included in Reprocessing			
	Particulate & Gas				
	Thermal				
Waste Disposal	Radiological, Ci	0	0	0	0
	Particulate & Gas	0	0	0	0
	Thermal				
Totals	Radiological, Ci	$1.94\text{x}10^7$	$3.7\text{x}10^7$	$4.3\text{x}10^7$	$5.1\text{x}10^7$
	Particulate & Gas				
	Thermal				

(a) Cu, curies of radioactivity..

(b) Heat in gigawatts.

(c) Heat in megawatts.

TABLE 11. SUMMARY OF ENVIRONMENTAL IMPACTS--WATER RECEPTORS

Stage of Cycle	Parameter	Year 1975	1980	1985	1990
U Mining	Radiological, Ci[a]				
	Chemical & Solid				
	Water Usage				
	Thermal				
U Milling	Radiological, Ci	1.2	2.4	4.7	8.1
	Chemical & Solid				
	Water Usage				
	Thermal				
Th Mining & Milling	Radiological, Ci	0	0	0	0
	Chemical & Solid				
	Water Usage				
	Thermal				
U Conversion	Radiological, Ci	.4	.7	1.2	1.9
	Chemical & Solid				
	Water Usage				
	Thermal				
U Enrichment	Radiological, Ci	2.2	4.1	6.4	10.5
	Chemical & Solid				
	Water Usage				
	Thermal				
Fuel Fabrication	Radiological, Ci	13.2	19.8	32.5	64.5
	Chemical & Solid				
	Water Usage				
	Thermal				
Reactor Operation	Radiological, Ci	2.7×10^5	8.0×10^5	1.5×10^6	2.4×10^6
	Chemical & Solid				
	Water Usage				
	Thermal	74×10^3(b)	132×10^3	196×10^3	305×10^3
Fuel Reprocessing	Radiological, Ci	2×10^4	2×10^4	2×10^4	2×10^4
	Chemical & Solid				
	Water Usage	2,600(c)	12,000	20,000	35,000
	Thermal	25(b)	60	100	190
Conversion	Radiological, Ci	Included in Reprocessing			
	Chemical & Solid				
	Water Usage				
	Thermal				
Waste Disposal	Radiological, Ci	0	0	0	0
	Chemical & Solid	0	0	0	0
	Water Usage	0	0	0	0
	Thermal	0	0	0	0
Totals	Radiological, Ci	2.7×10^5	8.0×10^5	1.5×10^6	2.4×10^6
	Chemical & Solid				
	Water Usage				
	Thermal				

(a) Ci, curies of radioactivity, where blanks exist, no evaluations were made.

(b) Heat in megawatts.

(c) Gallons/minute.

TABLE 12. SUMMARY OF ENVIRONMENTAL IMPACTS--LAND

Stage of Cycle	Parameter	1975	1980	1985	1990
U Mining	Radiological, Ci(a)				
	Chemical & Solid(b)	1.3×10^8	2.4×10^8	4.5×10^8	7.7×10^8
	Land Usage(c)	1,193	2,013	3,439	5,080
U Milling	Radiological, Ci	21,000	38,000	65,000	10.1×10^4
	Chemical & Solid				
	Land Usage				
Th Mining & Milling	Radiological, Ci	13	42	120	230
	Chemical & Solid				
	Land Usage				
U Conversion	Radiological, Ci	31	53	92	145
	Chemical & Solid				
	Land Usage				
U Enrichment	Radiological, Ci	0	0	0	0
	Chemical & Solid				
	Land Usage				
Fuel Fabrication	Radiological, Ci(e)	2×10^5	1.4×10^6	2.6×10^6	6.2×10^6
	Chemical & Solid(d,e)	1.9×10^4	3.4×10^4	5.9×10^4	1.0×10^5
	Land Usage-Waste(c)	1	1	1	2
Reactor Operation	Radiological, Ci(e)	6×10^5	1.5×10^6	2.8×10^6	5.2×10^6
	Chemical & Solid(d,e)	6×10^5	1.5×10^6	2.8×10^6	5.2×10^6
	Land Usage-Waste(c)	12	30	50	100
Fuel Reprocessing	Radiological, Ci(e)	2.9×10^5	1.5×10^6	2.9×10^6	1.3×10^8
	Chemical & Solid	2.6×10^5	6.8×10^5	1.1×10^6	2.2×10^6
	Land Usage-Waste	5	14	22	46
Conversion	Radiological, Ci	Included in Reprocessing			
	Chemical & Solid				
	Land Usage				
Waste Disposal (High Level)	Radiological, Ci	0	1.3×10^9	3.4×10^9	5.5×10^9
	Chemical & Solid	0	4,290(d)	11,220	18,180
	Land Usage				
Totals	Radiological, Ci	1.1×10^6	1.3×10^9	3.4×10^9	5.5×10^9
	Chemical & Solid				
	Land Usage				

(a) Ci, curies of radioactivity, where blanks exist, no evaluations were made.

(b) Cubic yards of waste rock from open pit and underground mining.

(c) Acres of land required/year.

(d) Ft^3 of solid waste/year.

(e) Shipped to offsite licensed contractor.

the various waste streams. Radiation hazard estimates require knowing the quantity, chemical, and physical form for each nuclide released to the environment.

Control Mechanisms and Costs

A great deal of attention is being and has been given to controlling the dispersal of wastes from the nuclear industry to minimize the risks to people and the environs.

From considerations of the radiological burden results given in Tables 10 through 12, it is evident that the major amounts of radioactive effluent release occur at the reprocessing plant, the power reactor plant, and the fuel fabrication plant. Therefore, the study has been concentrated on investigation of control mechanisms and associated costs for these three stages of the nuclear fuel cycle.

Reactor

The reactor waste treatment system is designed to collect all gases, liquids, and solids containing radioactivity and treat them to minimize radiation releases to the environment. A treatment system is provided for each. Although there will be some variations in the waste treatment systems for each reactor type, LWR's, HTGR's and LMFBR's, these differences are expected to be minor and consist primarily of chemical reaction systems for neutralizing or precipitating the liquid waste streams.

The average costs (1970) for radioactive waste treatment systems for a 1000 MWe (megawatts, electrical power) LWR reactor were $2,611,000 capital cost and $38,430 per year operating cost. Forecasting future waste facility capital costs is difficult because the policy of "as low as practicable" is not quantified. We estimate that the installation for "as low as practicable systems" is about $15 million per reactor and the operating costs will be about $500,000 per year.

In addition to radionuclide emissions, heat rejection from nuclear power plants is of concern. The waste heat from a power plant is released either to a water body or to the atmosphere. The costs for heat dissipation systems depend on the thermal efficiency of the plant and the cooling system used. Typical costs for once through cooling to water bodies range from $7 to $15 million; evaporative type cooling systems range from $14 to $22 million; and dry cooling systems range from $35 to $50 million. The cost of future control mechanisms for reducing thermal discharges could range from 0 to $30 million assuming the additional cost is that relative to the once-through-cooling-to-fresh-water cost ($7 million).

Fuels Reprocessing Plant

The reprocessing plant waste treatment systems consist of gas, liquid, and solid treatment systems. The LMFBR, HTGR, and LWR reprocessing plant waste treatment systems can be considered to be similar even though the processes are quite distinct. The primary sources of waste are: the fission productions separated from the thorium, uranium, and plutonium recycle streams, the transplutonium isotopes, small percentages of the uranium, thorium, and plutonium, and activated or contaminated processing material and corrosion products.

The costs incurred from the waste treatment facility are not very sensitive to the process used. For a 5 ton per day reprocessing plant, using 1970 costs, the waste treatment facility total capital cost is estimated to be $25 million. Annual operating costs are estimated to be $3 million per year. It is not unreasonable to assume that "as low as practicable" will become the guidelines for controlling releases from reprocessing plants in the future. It is assumed that releases of radioactive gas to the atmosphere will have to be controlled and the estimated costs for gas treatment facilities are $7 million capital costs and $1 million per year for operating costs.

Fuel Fabrication

All fabrication plants can be treated as being essentially similar as far as radioactive wastes and waste treatment are concerned. The principal wastes are airborne particulate which are controlled with filtered ventilation systems, and scrap which must be disposed of.

The average capital and operating costs for air treatment systems for a 5 ton a day plant are $2.2 million and $93 thousand per year, respectively. The average cost for water disposal is estimated at $19,000 per year. Capital costs for water disposal systems are estimated at $224,000. Applying as low as practicable releases to the fabrication industry could impose some additional control mechanisms and costs; however, no estimates have been made of these at this time.

Transportation

Since the nuclear fuel cycle has numerous industrial stages between the extraction of ore to deposit of radioactive wastes, there are numerous steps required in transporting nuclear materials in the nuclear power industry with shipments by truck being the secondary mode. The principal means of water transportation would be transcontinental freighter. In some steps of the process, the shipments may not go off-site.

The quantities of nuclear materials that will be shipped in these steps for the years 1975, 1980, 1985, and 1990 were estimated. In general, except for accidents, the impacts of shipments of nuclear materials are identical to transportation of any other material. It has been assumed that no releases occur during the transport of nuclear materials between process steps of the fuel cycle simply because we have assumed normal operational conditions. The impact of accidents has not been evaluated since this would require a statistical analysis of the frequency and severity of accidents for similar types of materials.

Experience to date indicates that the regulations now applicable assure a trivial impact to the environment. The AEC and others are currently conducting statistical evaluations of the frequency and severity of accidents and the attendant risk for shipments of spent fuel, recovered plutonium, and wastes. Assuming an accident would occur, a ranking of materials from most hazardous to least hazardous was made. This ranking is based simply upon the relative toxicity and chemical stability of the compounds. No judgment regarding the effectiveness of the container or shipping regulations was factored into the ranking. Plutonium (nitrate or oxide form) represents the most hazardous material with spent fuel and radioactive wastes being ranked second and third, respectively.

SECTION VI

ADVANCED ENERGY SYSTEMS

The energy resources used in this country through 1990 will be dominated by fossil fuel, with gradual, but substantial, increases in the use of nuclear fission energy. In the interests of conserving fossil fuels and of reducing the environmental burden, other energy sources must be developed to meet future demands. In order to establish which systems should receive preference, several potential energy systems were analyzed for their impact on the environment, their energy potential, and their developmental costs, capital cost, and cost of converting energy.

The objective of this phase of the study (which was secondary to the fossil fuel and conventional nuclear energy systems presented previously) was to identify and qualify selected advanced energy systems, quantify where possible the environmental burden, and rank the systems environmentally from best to worst. Additionally, systems were identified as to their potential for producing significant energy to meet national demand by 1975 and by 1990. A further task was to investigate the environmental burden influences of some miscellaneous energy systems, e.g., hydrogen energy. The study was carried out first by describing the state-of-the-art of the system under investigation and by describing subsystems within the main system. Next, the environmental burdens were considered. This was followed by an assessment, where possible, of the environmental control costs, the energy potential, and finally, the development costs to bring the system on stream. The energy systems investigated were as follows:

- Fuel Cells
- Solar
- Tidal
- Fusion
- Breeder Reactors
- Hydrogen
- Geothermal
- Energy Storage
- Magnetohydrodynamics
- Thermoelectric
- Thermionic
- Waste Heat Recovery
- Space Heating
- Insulation
- Heat Pumps

There are, of course, other energy systems under consideration, including ocean current thermal cycles, wind, and others, but it is believed that the significantly viable systems have been examined. As would be expected, source information was often conflicting or lacking. In cases where this was pertinent to the evaluation of the energy system, expert judgments were made.

All systems investigated are described in Appendices W and X.

Ranking of Energy Systems Environmentally

The prospective energy systems have been assigned to the categories excellent, good, fair, and poor as a qualitative measure of their relative environmental emission. This was done to avoid any implication of detailed quantitative relationships. A total of 23 systems has been listed in Table 13. Coal, gas, and nuclear fueled steam electric plants and hydroelectric plants have been included in this table for comparative purposes only. These four systems are considered to be conventional as they are currently at a high state of development, although environmental effects and conversion efficiencies are subject to change with continued development.

Residential heat pumps and solar heating systems are unlike the rest in that they are not directly related to electric power production. They were included because their future use would conserve fuel as a whole; however, the widespread use of heat pumps will tend to increase loads on central power plants.

Consideration was given to a wide range of factors, including thermal efficiency and cooling water requirements, potential for air pollution, land use requirements, environmental risks associated with fuel extraction, transport and processing, and the problems associated with disposal of waste product, whether fly ash, water soluble salts, or radioactive wastes. In some cases, there is conflicting information as to the potential environmental burden. Considerable effort was devoted to achieving a balance between optimism and pessimism.

Both positive and negative environmental burden were considered. For example, the negative fuel consumption of breeder reactors is a positive impact, as is the contribution to the solution of solid waste disposal problems when solid municipal waste is used as fuel in steam electric plants.

Because no generally accepted methodology is available for comparing the importance of fundamentally different burdens, value judgments and subjective considerations had to be used. The resulting rankings thus represent a consensus among a group of advanced energy system engineers and environmentalists.

Much of the reasoning behind the assignment of relative positions to the various systems is illustrated briefly as follows.

Fuel cell systems have at least two advantages over conventional steam electric systems; they are more efficient thermally and would produce substantially less air pollution. Those advantages may be illusory, however, because the fuel production would represent an additional step which would reduce overall efficiency. Moreover, if the fuel is

TABLE 13. ENVIRONMENTAL RANKING OF ADVANCED ENERGY SYSTEMS

Excellent

Solar Energy (Residential)(c)
Heat Pumps (Residential, Electric)(c)
Conventional Hydroelectric(a)

Good

Tidal
Geothermal (Hydrocracked dry rock)(c)
Solar (Rankine cycle)(c)
Solar (Stirling)(c)
Geothermal (Natural)(b,c)
Fusion
Solar (Satellite)
Solar (Photovoltaic)
Natural gas/steam/electric(a)

Fair

Geothermal (Nuclear stiumlated)
Magnetohydrodynamic (Closed cycle, nuclear)(c)
Breeder reactors (Gas-cooled(c), liquid metal(c), and molten salt)
Fuel Cells (Coal-to-hydrogen gasification)(c)
Light Water Nuclear Reactors(a,b,c)
Fuel Cell (Nuclear-electrolytic hydrogen)(c)
Thermoelectric (Solar)
Gasified coal/steam/electric(c)
Magnetohydrodynamic (Open-cycle - coal/steam/electric)(c)

Poor

Coal/Steam/Electric(a)
Thermionic (Nuclear)

(a) The conventional systems in 1972 are included for reference purposes only.
(b) Capable of producing significantly increased energy by 1975.
(c) Capable of producing significant energy by 1990.

produced by gasifying fossil fuels, there would be some production of conventional air pollutants.

The solar energy systems are widely considered to be environmentally "clean". However, the collectors would require the dedication of very large land areas. Systems using satellite collectors would require beam transmission of the energy to receivers on the ground. Some concern has been expressed for the potential hazard associated with the relatively intense beam of electromagnetic radiation.

Residential heat pumps represent largely beneficial environmental impact because they would reduce the demand for fuel resources. On the other hand, there might be a requirement for supplementary space heating at times for which resistance heating systems appear attractive. In that case, widespread use of heat pumps might lead to increased central power station load, with attendant environmental insults, during the most severe part of the heating season.

The various approaches suggested for utilizing geothermal energy are all site limited, and all appear to require dedication of substantial amounts of land, much of which is presently scenic. In addition, there is a potential for the contamination of surface water with dissolved salts, and for air pollution with hydrogen sulfide or ammonia, for example. Concern has also been expressed over possible subsidence of relatively large areas, and for possible seismic activity as a result of deep well injection.

Controlled Thermonuclear Fusion reactors have several potential advantages over fission reactors and fossil-fueled plants. They should be more efficient, thus requiring less cooling capacity; there will be no combustion products; and radioactive wastes will be largely contained. However, there will be substantial tritium production, and the reactor structures will be radioactive.

Utilization of tidal currents to produce electricity is attractive as a nonpolluting system. However, there are several environmental factors, including alteration of estuaries, both physically and biologically, and the potential for local or meso-scale alteration of weather and climate.

Breeder reactors as a group have similarly been mentioned as having a decided environmental emission advantage because of their fuel production as opposed to consumption. However, their thermal efficiency is not altogether favorable, and their production of tritium and fission products which must be stored for decay represent adverse environmental factors. In addition, the shipment and reprocessing of fuel in large quantities represents a certain environmental risk because of the possibility of accidents.

Magnetohydrodynamic power systems receive much favorable attention largely because of their relatively high thermal efficiency. Seed recovery must be thorough for economic as well as environmental reasons, but it is not known how important might be the escape of relatively small amounts, by weight, of very small diameter seed particles which are extremely difficult to capture. Sulfur recovery within the system is a decided bonus but the very high temperatures associated with MHD will tend to enhance production of oxides of nitrogen.

Thermoelectric and thermionic systems are not expected to provide any significant power to meet national demands by 1990.

Discussion of Advanced Energy Systems With Regard to Their Ability to Produce Significant Energy

Of the systems presented in Table 13, only natural geothermal is capable of providing significantly increased amounts of energy by 1975 without serious detriment to the environment.

The most striking potential advances in energy by 1990 are estimated to be in LW nuclear electric and gasified coal-steam electric plants. The gasified coal utilization in fuel cells to produce electrical energy with relatively low environmental burdens at the point of utilization looks promising by 1990. This may also be true for electrolytically produced hydrogen-fuel cell systems from surplus nuclear-generated electricity if the capital costs can be made competitive.

By 1990, solid waste utilization could account for 5 percent of the total energy demand. This could also be true for residential use of solar energy and heat pumps but solar energy storage systems and capital costs economics need to be more firmly established.

Magnetohydrodynamic topping systems for peaking power demands should be in use by 1990. Because of the very large energy potential, dry rock geothermal system feasibility needs to be established. Significant power from this source could become available by 1990 at very modest environmental burdens if shown to be economically competitive.

SECTION VII

MISCELLANEOUS ENERGY SYSTEMS

Hydrogen energy (and a fuel cell total energy system utilizing hydrogen), space heating and insulation, energy storage, and waste heat recovery, were examined for their influence on the environment. Generally, these systems have a favorable environmental impact: the combustion of hydrogen produces little or no burden; the use of insulation diminishes space-heating fuel emissions and conserves energy resources; energy storage, particularly as compressed gaseous fuel or as compressed air for turbine power, decreases the environmental burden; and waste heat recovery, where it is economically practical, diminishes the thermal pollution of streams and air as well as representing potential resource conservation.

The systems are qualitatively ranked as follows:

- Hydrogen energy
- Space heating and insulation
- Energy storage
- Waste heat recovery.

Hydrogen is a very versatile fuel which is capable of providing large quantities of electrical and other forms of energy including synthetic liquid and gaseous fuels. Until natural gas supplies or comparative costs make hydrogen economically competitive, the incentive to move swiftly toward a "hydrogen economy" is not present, and therefore, it is unlikely that significant energy will be developed from this source through 1990.

The assault on the environment caused by producing hydrogen by coal gasification and hydrogen utilization to produce steam-electric power is considered to be less than conventional coal-steam-electric plants. Nuclear power-water electrolysis produced hydrogen will have little more environmental impact than the LW nuclear electric plant itself except for the inefficiencies of electrolysis and reconversion of the hydrogen to electricity. An important consideration in the utilization of hydrogen is that it will not contribute undesirable emissions at the point of utilization either as fuel for fuel-cells or for steam generation when electrolytically produced hydrogen and oxygen are used as the energy source.

Space heating consumes about 20 percent of the nation's energy. Environmental emissions from air pollution emission can be effected by fuels, equipment design, equipment adjustments, and thermal insulation of the structures.

The analyses presented in Appendix X for residential, commercial, and industrial space heating are based on simplified cases using average emission factors for different fuel-types in general classes of equipment. An important consideration that is masked by the use of averages is the wide difference in emission performance between different heating units within a class; in view of this factor, continued R&D effort is needed to establish criteria for the design, operation, and maintenance of combustion equipment for minimum emissions.

Improved thermal insulation is one of the most effective, simple, economical, and immediate control measures for air pollution emissions from space heating--and an approach that can be implemented by individual home owners.

Hydro-pumped energy storage has proved to be the only practical system thus far developed to store large quantities of energy recovered from other systems, but its undesirable utilization of land as reservoirs is a decided deterrent to its widespread use.

The elctrochemical storage of off-peak energy by means of water electrolysis-fuel cell combination in which the hydrogen and oxygen are stored for later use, offer some attractive possibilities. Unlike hydro-pumped storage, electrochemical storage is not seriously site restrictive. When used in conjunction with nuclear plants, electrochemical storage of energy would tend to decrease the environmental burden as compared with pumped storage of fossil-fueled plants.

Like natural gas, hydrogen may be stored as compressed gas or by liquefaction. Though this may be accomplished without serious aesthetic insult to the environment, the matter of leakage of hydrogen from underground storage and gaseous emissions associated with the combustion process associated with the compressor prime movers may contribute to the environmental burden.

Compressed air storage from gas turbine power generating equipment during off-peak loads for reuse during peak loads appears to be quite attractive. The gas turbine will produce only 1/3 the combustion products as environmental burden since it is unnecessary to provide power to the compressor during the period when the compressed air storage is used. This system has not as yet been utilized extensively, however.

Waste heat is generally regarded as the heat rejected in power cycles, especially those associated with the generation of electricity. Waste heat recovery and its utilization to produce useful products, and thereby unburden the environment, hold very marginal promise economically. Financial incentives exist in the areas of climate control (particularly in community total energy systems), agriculture, and aquaculture. As higher priority is placed on the conservation of energy resources, a further enhancement of the benefits from waste heat recovery is to be expected.

More detailed descriptions of the energy systems, their environmental burdens and, where possible, their environmental control costs, and development costs to bring the system on stream to meet future energy demands are presented in Appendices W and X.

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DATA TABLES FOR SELECTED MODULES

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APPENDIX A

DATA TABLES FOR SELECTED MODULES

The unit emissions data derived for each of the modules are given in the following tables. The source of original data and the assumptions made are given in footnotes to each table, so that the calculations can be repeated. The references cited are listed at the end of this Appendix.

TABLE A-1. ENVIRONMENTAL DATA FOR MODULE

Module - Strip Mined Coal, East
Unit - 10^6 Btu (output)

Environmental Parameters	With Land Restoration and Treatment of Acid Drainage(1)
Air	
NO_x, lb	0.0002(2)
SO_2, lb	Negligible
CO, lb	Negligible
Particulate, lb	0.14(3)
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible
Water	
Suspended solids, lb	0.55(4)
Dissolved solids, lb	0.18
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible
Acid (H_2SO_4), lb	Nil
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0.24(5)
Tailings, lb	Negligible
Hazardous, lb	0
By-Products	None
Occupational Health	
Deaths	5 x 10^{-9}(6)
Total Injuries	2.5 x 10^{-7}(7)
Man Days Lost	7.4 x 10^{-5}(8)
Land Use, acre-hr/10^6 Btu	0.3(9)
Approx. Module Efficiency	99.6%(10)

Footnotes for Table A-1:

(1) Impacts will be negligible after land restoration. Stated impacts will occur during the actual operation.

(2) a. NO_x released to atmosphere from reclamation operation was derived based on the assumption that a diesel powered bulldozer is used for reclamation.
b. Time requirement for reclamation (assumed) = 4 hr/acre.
c. Bulldozer engine power (assumed) = 150 hp.
d. Fuel consumption rate$^{(A-1)}$ = 0.5 lb/hp-hr.
e. Emission factor$^{(A-1)}$ = 0.37 lb NO_x/gal of fuel used.
f. Average thickness of coal seam (assumed) = 2 ft.
g. Coal density (assumed) = 82 lb/ft^3.
h. Heating value of coal (assumed) = 12,000 Btu/lb.

(3) a. Emission factor (same as primary rock crushing and copper mining) = 0.1 lb/ton of overburden.
b. Average overburden per ton of coal (private communication, EPA) = 33 tons.

(4) a. Rate of silt run-off (assumed = 5000 tons/Mi^2-year.
b. Average thickness of coal seam (assumed) = 2 ft.
c. Coal bulk density (assumed) = 82 lb/ft^3.
d. Reclamation period (assumed) = 3 years

(5) a. Dissolved solids ($CaSO_4$) and sludge ($FeOH_2$) come from acid treatment (assumed).
b. Drainage water discharge rate for a strip coal mine with a capacity of 10^6 ton coal/year (assumed) = 10^6 gal/day.
c. Acidity of drainage water (assumed) = 1000 ppm.

(6) a. Death rate for strip coal mining$^{(A-12)}$ = 0.12/10^6 ton coal.
b. Heating value of coal (assumed) = 24 x 10^6 Btu/ton coal.

(7) a. Injury rate for strip coal mining$^{(A-12)}$ = 5.65 injuries/10^6 ton coal.

(8) a. Man-days lost per death (assumed) = 6000 days/death.
b. Man-days lost per injury (assumed) = 180 days/injury.

(9) a. Land required for 10^6 tons of coal$^{(A-12)}$ = 280 acres.
b. Time required for reclamation (assumed) = 3 years.

(10) a. Efficiency of strip mine operation (assumed) = 99.6%.
b. Depletive waste not included.

TABLE A-2. ENVIRONMENTAL DATA FOR MODULE

Module - Strip-mined coal, West
Unit - 10^6 Btu (output)

Environmental Parameters	With Land Restoration and Treatment of Acid Drainage(1)
Air	
NO_x, lb	0.00008 (Bulldozer operation)(2)
SO_2, lb	Negligible
CO, lb	Negligible
Particulate, lb	0.07(3)
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible
Water	
Suspended solids, lb	0.28(4)
Dissolved solids, lb	Not determined
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible
Acid (H_2SO_4), lb	Nil
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	None
Occupational Health	
Deaths	6.5×10^{-9}(5)
Total Injuries	3.1×10^{-7}(6)
Man Days Lost	9.6×10^{-5}(7)
Land Use, acre-hr/10^6 Btu	0.16(8)
Approx. Module Efficiency	99.8%

Footnotes for Table A-2:

(1) a. Impacts will be negligible after land restorations. Stated impacts will occur during the actual operation.

(2) a. NO_x comes from a disel powered bulldozer used for reclamation.
  b. Time requirement for reclamation (assumed = 4 hr/acre.
  c. Bulldozer engine power (assumed) = 150 hp.
  d. Fuel consumption rate(A-1) = 0.5 lb/hp - hr.
  e. NO_x emission factor(A-1) = 0.37 lb/gal fuel used.
  f. Average thickness of coal seam (assumed = 5 ft.
  g. Coal bulk density (assumed) = 82 lb/ft^3.
  h. Heating value of western coal (assumed) = 9235 Btu/lb.

(3) a. Emission factor (given for suspended particulate from primary rock crushing and for mining of copper ore) = 0.1 lb/ton of overburden.
  b. Average overburden per ton of coal = 13 tons.

(4) a. Rate of silt run-off (assumed) = 5000 $tons/mi^2$-year.
  b. Average thickness of coal seam (assumed) = 5 ft.
  c. Coal bulk density (assumed) = 82 lb/ft^3.
  d. Reclamation period (private communication, EPA) = 3 years.

(5) a. Death rate for strip coal mining(A-12) = $0.12/10^6$ ton coal.
  b. Heating value of coal (assumed) = 18.47×10^6 Btu/ton of coal.

(6) a. Injury rate for strip coal mining(A-12) = 5.65 injuries/10^6 ton coal.

(7) a. Man-days lost per death (assumed) = 6000 days/death.
  b. Man-days lost per injury (assumed) = 182.6 days/injury.

(8) a. Land required for 10^6 tons of coal(A-12) = 112 acres.
  b. Time requirement for reclamation (assumed) = 3 years.

(9) a. Efficiency of strip mine operation (assumed) = 99.8%.

TABLE A-3. ENVIRONMENTAL DATA FOR MODULE

Module - Eastern Deep-Mined Coal
Unit - 10^6 Btu (output)

Environmental Parameters	With Treatment of Acid Drainage
Air	
NO_x, lb	0
SO_2, lb	0
CO, lb	0
Particulate, lb	Negligible
Total organic material, lb	0
Heat, 10^6 Btu	0
Water	
Suspended solids, lb	Negligible
Dissolved solids, lb	0.06(1)
Total organic material, lb	0
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0.02(2)
Tailings, lb	3(3)
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	3×10^{-8}(4)
Total Injuries	1.3×10^{-6}(5)
Man Days Lost	7.3×10^{-4}(6)
Land Use, acre-hr/10^6 Btu	0.74(7)
Approx. Module Efficiency	99.6%(8)

Footnotes for Table A-3:

(1) a. Amount of acid drainage from deep coal mine attributable to 1000 MW plant per year$^{(A-12)}$ = 23050 tons/year.
    b. Total sulfur content$^{(A-12)}$ = 0.2%.
    c. Reclamation time required (assumed) = 10 years.
    d. Dissolved solid material (assumed) = $CaSO_4$.

(2) a. Total dissolved iron content in acid mine drainage$^{(A-12)}$ = 0.167%.
    b. Form of sludge (assumed) = $Fe(OH)_3$.

(3) a. Waste factor$^{(A-14)}$ = 0.036 tons waste/ton coal mined.

(4) a. Death rate$^{(A-12)}$ = 2 deaths/67.1 x 10^{12} Btu.

(5) a. Injury rate$^{(A-12)}$ = 86.8 injuries/67.1 x 10^{12} Btu.

(6) a. Man-days lost$^{(A-12)}$ = 48807 days/67.1 x 10^{12} Btu.
    b. This number includes days lost due to Pneumoconiosis$^{(A-12)}$.

(7) a. Land requirement$^{(A-12)}$ = 569.4 acres/67.1 x 10^{12} Btu.
    b. Reclamation period (assumed) = 10 years.

(8) a. Efficiency of deep mine operation (assumed) = 99.6%.

TABLE A-4. ENVIRONMENTAL DATA FOR MODULE

Module - Physical cleaning of coal
Unit - 10^6 Btu (output)

Environmental Parameters	Without Environmental Control	With Environmental Control
Air		
NO_x, lb	0.006(1)	0.006(1)
SO_2, lb	0.036(2)	0.004(3)
CO, lb	--	--
Particulate, lb	1.0(4)	0.01(5)
Total organic material, lb	--	--
Heat, 10^6 Btu	--	--
Water		
Suspended solids, lb	2.13(6)	Negligible
Dissolved solids, lb	0.15(7)	Negligible
Total organic material, lb	0.003(8)	Negligible
Heat, 10^6 Btu	--	--
Acid (H_2SO_4), lb	0.01(9)	Negligible
Solid		
Slag, lb	0	0
Ash, lb	0	0
Sludge, lb	0	0.3(10)
Tailings, lb	9.5(11)	Negligible
Hazardous, lb	0	0
By-Products	0	0
Occupational Health		
Deaths	3.0×10^{-9}(12)	3.0×10^{-9}
Total Injuries	6.0×10^{-8}(12)	6.0×10^{-8}
Man Days Lost	2.6×10^{-5}(13)	2.6×10^{-5}
Land Use, acre-hr/10^6 Btu	0.003(14)	0.003
Approx. Module Efficiency	88%(15)	88%

Footnotes for Table A-4:

(1) a. NO_x from thermal dryer. Operating characteristics for evaporating water from wet coal$^{(A-2)}$ = 550 tons of coal produced per 50 tons of water evaporated.
b. Heat required for water evaporation = 1000 Btu/lb water.
c. Heating value of coal = 12,000 Btu/lb of coal.
d. NO_x emission factor$^{(A-1)}$ = 18 lb/ton of coal burner.
e. No control equipment.

(2) a. SO_2 emission factor$^{(A-1)}$ = 38 lb/ton coal burned.
b. No control equipment.
c. Sulfur content of coal, S (assumed) = 3%.

(3) a. Lime scrubber control efficiency (assumed) = 90%.

(4) a. Particulate emission factor for thermal dryer$^{(A-1)}$ = 25 lb/ton coal product.
b. Heating value of coal product = 13,180 Btu/lb.
c. No control equipment.

(5) a. Control efficiency of multiple cyclones with wet scrubber$^{(A-1)}$ = 99.0% removal.

(6) a. Calculations are based on West Virginia coal.
b. Coal produced in 1963$^{(A-3)}$ = 132,568,000 tons.
c. Water discharged to environment in 1962$^{(A-3)}$ = 5,141 x 10^6 gal.
d. Suspended solid in water$^{(A-3)}$ = 15%.
e. Density of slurry (assumed) - 62.4 lb/ft^3.

(7) a. Dissolved solid in water (assumed) = 1%.

(8) a. Organic material in the form of alcohol added as a frother in the processing of fines in amounts of 0.3 lb/ton produced.
b. 20% of coal produced comes from fines (assumption).

(9) a. Measured acidity (H_2SO_4)$^{(A-2,A-4)}$ = 198 lb $CaCO_3$/acre-hr.
b. Based on a 1,000 ton/hr capacity plant.
c. 10% of input shows up as tailings (assumed).
d. Bulk density of tailings (assumed) = 0.8 lb/ft^3 .
e. Average height of the pile (assumed) = 30 ft.
f. Area occupied by refuse - 27 acres.

(10) a. Sludge comes from SO_2 and H_2SO_4 control (assumed).
b. Sulfur content of sludge (assumed) = 12%.

(11) a. 10% of input shows up as tailings (assumed).
b. Plant efficiency taken as 88% (losses include tailings, coal burned for drying and other energy requirements).

(12) a. Basis: 40 men operate a 100 ton/hr capacity sand and gravel plant.
b. Assumption: 80 men operate a 1,000 ton/hr capacity coal cleaning plant.
c. Average injuries and man-days lost per million man-hours for sand and gravel industry and stone quarrying and milling industry are 18.1 injuries/10^6 man-hours and 2,630 days lost/10^6 man-hours, respectively.$^{(A-5)}$
d. Death rate is assumed as 5% of the injuries.

(13) a. Man-days lost per death is assumed as 6,000 days/death.

(14) a. Assume 75 acres required for a 1,000 ton/hr capacity plant and refuse pile.

(15) a. The efficiency is assumed to be 88%.

TABLE A-5. ENVIRONMENTAL DATA FOR MODULE

Module - Chemical Cleaning of Coal
Unit - 10^6 Btu (Output)

Environmental Parameters	Fuel Input, Coal
Air	
NO_x, lb	0.04(1)
SO_2, lb	0.1(2)
CO, lb	0.002(3)
Particulate, lb	0.005(4)
Total organic material, lb	0
Heat, 10^6 Btu	0.05(5)
Water	
Suspended solids, lb	Negligible
Dissolved solids, lb	Trace
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible
Acid (H_2SO_4), lb	Negligible
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	4.3(6)
Occupational Health	
Deaths	1.4×10^{-9}(7)
Total Injuries	2.7×10^{-8}(7)
Man Days Lost	6.5×10^{-6}(8)
Land Use, acre-hr/10^6 Btu	0.08(9)
Approx. Module Efficiency	95%(10)

Footnotes for Table A-5:

(1) a. 100 lb of product coal is burned in the production of ton of product coal (assumed).
b. NO_x emission factor$^{(A-1)}$ = 18 lb/ton coal burned.
c. Heating value of chemically cleaned coal (assumed) = 24×10^6 Btu/ton coal.

(2) a. Sulfur content of chemically cleaned coal, S (assumed = 1.22%.
b. SO_2 emission factor$^{(A-1)}$ = 3.85 lb/ton coal burned

(3) a. CO emission factor$^{(A-1)}$ = 1 lb/ton coal burned.

(4) a. Particulate emission factor$^{(A-1)}$ = 16 A lb/ton coal burned.
b. Ash content of chemically cleaned coal, A (assumed) = 14.4%.
c. Electrostatic precipitator efficiency (assumed) = 99%.

(5) a. Efficiency of plant operation (assumed) = 95%.

(6) a. Elemental sulfur = 0.6 lg/10^6 Btu.
b. $FeSO_4$ = 3.7 lb/10^6 Btu.

(7) a. 80 men operate a 1000 ton/hr capacity chemical coal cleaning plant (assumed).
b. Using chemical industry data, injuries per man-hour$^{(A-5)}$ = 8.1 injuries/10^6 man hours.
c. Using chemical industry data, days lost per man hour$^{(A-5)}$ = 528 days/10^6 man hours.
d. Death rate (assumed) = 5% of total injuries.

(8) a. Man-day lost per death (assumed) = 6000 days/death.

(9) a. Land requirement for a 400 tons coal/hr capacity plant (assumed) = 750 acres.

(10) a. Plant efficiency (assumed) = 95%.

TABLE A-6. ENVIRONMENTAL DATA FOR MODULE

Module - Coal Liquefaction (solvent refining)
Unit - 10^6 Btu (output)

Environmental Parameters	Fuel Input, Eastern Coal(1)
Air	
NO_x, lb	0.21(2)
SO_2, lb	0.003(3)
CO, lb	0.012(4)
Particulate, lb	0.27(5)
Total organic material, lb	0.0036(6)
Heat, 10^6 Btu	0.067(7)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	Trace
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	16.0(8)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	2.95(9)
Occupational Health	
Deaths	1.4×10^{-9}(10)
Total Injuries	2.7×10^{-8}(10)
Man Days Lost	6.5×10^{-6}(11)
Land Use, acre-hr/10^6 Btu	0.08(12)
Approx. Module Efficiency	75%(13)

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(1) Impacts were estimated based on the coal containing 14.4% ash, 3.0% S and a heating value of 12,000 Btu/lb. In addition, the coal liquefaction plant was assumed to have a capacity of 222×10^9 Btu/day.

Footnotes for Table-A-6 (Continuted):

(2) a. Solvent refined coal (SRC) has a heating value of 16,000 Btu/lb, 0.05% ash, and 0.6% sulfur$^{(A-6)}$.
b. Plant efficiency$^{(A-6)}$ = 75%.
c. Emission factor for NO_x = 18 lb/ton of coal burned.
d. Average heating value of consumed coal = 14,000 Btu/lb.
e. Coal consumption rate = 110 tons/hr.

(3) a. Total sulfur content in the input coal = 30,833 lb/hr.
b. Total sulfur content in the SRC = 3.469 lb/hr.
c. Sulfur emitted as SO_2 = 0.1% total sulfur off gas-liquid separator.

(4) a. CO emission factor$^{(A-1)}$ = 1 lb/ton of coal burned.
b. No control equipment.

(5) a. Particulate emission factor$^{(A-1)}$ = 16A lb/ton of coal burned.
b. Emission control efficiency (assumed) 98%.
c. Average ash content of consumed coal, A = 7.23%.

(6) a. Total organic material emission factor = 0.3 lg/ton of coal burned.
b. No control equipment.

(7) a. Total heat released = 0.308 x 10^{10} Btu/hr.

(8) a. Total ash input rate = 148,000 lb/hr.
b. Total ash output rate in SRC = 289 lb/hr.

(9) Elemental sulfur product = 99.9% of total sulfur-off gas, liquid separator.

(10) a. Assumption: 80 men operate a 1,000 ton/hr capacity solvent refining plant.
b. Use chemical industry data, injuries per man hour$^{(A-5)}$ = 8.1 injuries/10^6 man hours.
c. Use chemical industry data, days lost per man hour$^{(A-5)}$ = 528 days lost/10^6 man hours.
d. Death rate = 5% of total injuries (assumed).

(11) Man days lost per death (assumed) = 6,000 days/death.

(12) Land required for a 222 x 10^9 Btu/day plant (assumed) = 750 acres.

(13) Plant efficiency$^{(A-6)}$ = 75%.

TABLE A-7. ENVIRONMENTAL DATA FOR MODULE

Module - Railroad Transportation of Coal
Unit - 10^6 Btu (output)

Environmental Parameters	Fuel Input, Coal
Air	
NO_x, lb	0.02(1)
SO_2, lb	0.0014(2)
CO, lb	0.015(3)
Particulate, lb	0.0015(4)
Total organic material, lb	Negligible
Heat, 10^6 Btu	0.0039(5)
Water	
Suspended solids, lb	Negligible
Dissolved solids, lb	Negligible
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible
Acid (H_2SO_4), lb	Negligible
Solid	
Slag, lb	Negligible
Ash, lb	Negligible
Sludge, lb	Negligible
Tailings, lb	0.083(6)
Hazardous, lb	Negligible
By-Products	Negligible
Occupational Health	
Deaths	3.2×10^{-8}(7)
Total Injuries	3.2×10^{-7}(8)
Man Days Lost	2.2×10^{-4}(9)
Land Use, acre-hr/10^6 Btu	0.29(10)
Approx. Module Efficiency	100%(11)

Footnotes for Table A-7:

(1) a. Total quantity of coal transported$^{(A-7)}$ = 695 x 10^6 tons/year.
b. Total shipment from rail and barge$^{(A-8)}$ = 8.13%.
c. Total shipment from rail (assumed) = 7.13%.
d. NO_x emission per 10^6 hp-hr$^{(A-9)}$ = 15.43 tons/10^6 hp-hr.
e. Assume a 3,000 horsepower required for each 2,000 tons of gross load in a locomotive-train system.
f. Average horsepower of the locomotive-train system$^{(A-10)}$ = 74.9% of the maximum horsepower.
g. Ratio of average gross tonnate to average net tonnage$^{(A-10)}$ = 2.3481.

(2) a. SO_2 emission per 10^6 hp-hr$^{(A-9)}$ = 1.1 tons/10^6 hp-hr.

(3) a. CO emission per 10^6 hp-hr$^{(A-9)}$ = 11.9 tons/10^6 hp-hr.

(4) a. Particulate emission (assumed) = 10% of CO.

(5) a. Hp-hr required to move the ton-mill of coal transported by rail per year = 7554.6 x 10^6 hp-hr/yr.
b. Definition and value of the brake thermal efficiency$^{(A-11)}$=

$$\frac{\text{Fuel flow/Brake fuel consumption}}{\text{[Fuel flow] Fuel heating value}} = \frac{(100/(0.456)}{(19{,}156)(3.929 \times 10^{-4})} = 29.1\%.$$

c. Energy that the fuel carries into the locomotive = 2.59 x 10^{10} hp-hr/year.

(6) a. The fraction of intransit storage-handling dust loss = 0.1% of the total coal transported.

(7) a. Number of death occurred on the railroad system$^{(A-10)}$ = 2299 death/year.
b. Total ton-miles shipped by rail$^{(A-8)}$ = 7.7 x 10^{11} tons/year.
c. Ton-miles shipped for coal by rail$^{(A-8)}$ = 1.26 x 10^{11}/year.

(8) a. Number of injuries occurred on the railroad system$^{(A-10)}$ = 23356 injuries/year.

(9) a. Man days lost per death (assumed) = 6000 man days.
b. Man days lost per injury (assumed) = 100 man days.

(10) a. Current land rights of the railroad system$^{(A-10)}$ = 3760 sq miles.

(11) a. Module efficiency (assumed) = 100%.

TABLE A-8. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Boiler
Unit - 10^6 Btu (Input)

Environmental Parameters	Fuel Input, Eastern Coal
Air	
NO_x, lb	0.75(1)
SO_2, lb	4.75(2)
CO, lb	0.042(3)
Particulate, lb	0.1(4)
Total organic material, lb	0.013(5)
Heat, 10^6 Btu	0.63(6)
Water	
Suspended solids, lb	0.025(7)
Dissolved solids, lb	0
Total organic material, lb	0.011(8)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	12.0(9)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	3.3×10^{-10}(10)
Total Injuries	1.4×10^{-8}(10)
Man Days Lost	5.1×10^{-6}(11)
Land Use, acre-hr/10^6 Btu	0.1(12)
Approx. Module Efficiency	37%(13)

Footnotes for Table A-8:

(1) a. NO_x emission factor$^{(A-1)}$ = 18 lb/ton of coal burned.

(2) a. SO_2 emission factor$^{(A-1)}$ = 38 S lb/ton of coal burned.
    b. Sulfur content, S (assumed) = 3%.

(3) a. CO emission factor$^{(A-1)}$ = 1 lb/ton coal burned.

(4) a. Particulate emission factor$^{(A-1)}$ = 16A lb/ton coal burned.
    b. Ash content, A (assumed) = 14.4%.
    c. Electrostatic precipitator efficiency (assumed) = 99%.

(5) a. Hydrocarbons emission factor$^{(A-1)}$ = 0.3 lb/ton coal burned.

(6) a. Efficiency of conventional boiler (assumed) = 37%.

(7) a. Total solid to water$^{(A-12)}$ = 0.036 lb/10^6 Btu.
    b. Fraction of suspended solid (assumed) = 70%.

(8) a. Fraction of organic material in total solid (assumed) = 30%.

(9) a. Ash content of coal (assumed) = 14.4%

(10) a. Man-hours required per 10^6 Btu for conventional power plant$^{(A-13)}$ = 2.4×10^{-3} man-hour/10^6 Btu.
    b. Total injuries per 10^6 man hour$^{(A-13)}$ = 5.7.
    c. Death rate$^{(A-12)}$ = 2.4% of injuries.

(11) a. Days lost per death (assumed) = 6000 days/death.
    b. Days lost per injury (assumed) 229 days/injury.

(12) a. Land required for a 1000 MW power plant (assumed) = 800 acres.

(13) a. Efficiency of conventional boiler (assumed) = 37%.

TABLE A- 9. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Boiler (Coal)
Unit - 10^6 Btu (Input)

Environmental Parameters	Fuel Input, Coal, West
Air	
NO_x, lb	0.98(1)
SO_2, lb	1.65(2)
CO, lb	0.054(3)
Particulate, lb	0.07(4)
Total organic material, lb	0.016(5)
Heat, 10^6 Btu	0.63(6)
Water	
Suspended solids, lb	0.025(7)
Dissolved solids, lb	0
Total organic material, lb	0.011(8)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	9.0(9)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	3.3×10^{-10}(10)
Total Injuries	1.4×10^{-8}(10)
Man Days Lost	5.1×10^{-6}(11)
Land Use, acre-hr/10^6 Btu	0.1(12)
Approx. Module Efficiency	37%(13)

Footnotes for Table A-9:

(1) a. NO_x emission factor$^{(A-1)}$ = 18 lb/ton coal burned.
    b. Heating value of western coal (assumed) 9200 Btu/lb.

(2) a. SO_2 emission factor$^{(A-1)}$ = 38 S lb/ton coal burned.
    b. Sulfur content, S (assumed) = 0.8%.

(3) a. CO emission factor$^{(A-1)}$ = 1 lb/ton coal burned.

(4) a. Particulate emission factor$^{(A-1)}$ = 16A lb/ton coal burned.
    b. Ash content, A (assumed) = 8.4%.
    c. Electrostatic precipitator efficiency (assumed) = 99%.

(5) a. Hydrocarbons emission factor$^{(A-1)}$ = 0.3 lb/ton coal burned.

(6) a. Efficiency of conventional boiler (assumed) = 37%.

(7) a. Total solid to water$^{(A-12)}$ = 0.036 lb/10^6 Btu.
    b. Fraction of suspended solid (assumed) = 70%.

(8) a. Fraction of organic material in total solid (assumed) = 30%.

(9) a. Ash content of coal (assumed) = 8.4%.

(10) a. Man-hour required per 10^6 Btu for conventional power plant$^{(A-13)}$ = 2.4×10^{-3} man hour.
    b. Total injuries per 10^6 man-hour$^{(A-13)}$ = 5.7.
    c. Death rate$^{(A-12)}$ = 2.4% of injuries.

(11) a. Days lost per death (assumed) = 6000 days/death.
    b. Days lost per injury (assumed) = 229 days/death.

(12) a. Land required for a 1000 MW power plant (assumed) = 800 acres.

(13) a. Efficiency of conventional boiler (assumed) = 37%.

TABLE A-10. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Boiler
Unit - 10^6 Btu (Input)

Environmental Parameters	Fuel Input, Physically Clean
Air	
NO_x, lb	0.68(1)
SO_2, lb	2.02(2)
CO, lb	0.038(3)
Particulate, lb	0.044(4)
Total organic material, lb	0.011(5)
Heat, 10^6 Btu	0.63(6)
Water	
Suspended solids, lb	0.025(7)
Dissolved solids, lb	0
Total organic material, lb	0.011(8)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	5.41(9)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	3.3×10^{-10}(10)
Total Injuries	1.4×10^{-8}(10)
Man Days Lost	5.1×10^{-6}(11)
Land Use, acre-hr/10^6 Btu	0.1(12)
Approx. Module Efficiency	37%(13)

Footnotes for Table A-10:

(1) a. NO_x emission factor$^{(A-1)}$ = 18 lb ton coal burned.
b. Heating value of physically cleaned coal = 13,180 Btu/lb.

(2) a. Sulfur content, S (assumed) = 1.4%.
b. Emission factor for $SO_2$$^{(A-1)}$ = 38 S lb/ton coal burned.

(3) a. CO emission factor$^{(A-1)}$ = 1 lb/ton coal burned.

(4) a. Ash content of coal, A (assumed) = 7.25%.
b. Particulate emission factor$^{(A-1)}$ = 16A lb/ton coal burned.
c. Electrostatic precipitator efficiency (assumed) = 99%.

(5) a. Hydrocarbon emission factor$^{(A-1)}$ = 0.3 lb/ton coal burned.

(6) a. Efficiency of conventional boiler (assumed) = 37%.

(7) a. Total solid to water$^{(A-12)}$ = 0.036 lb/10^6 Btu.
b. Fraction of suspended solid (assumed) = 70%.

(8) a. Fraction of organic material in total solid (assumed) = 30%.

(9) a. Ash content of coal (assumed) = &.25%.

(10) a. Man-hour required per 10^6 Btu for conventional power plant$^{(A-13)}$ = 2.4×10^{-3} man-hour/10^6 Btu.
b. Total injuries per 10^6 man hours$^{(A-13)}$ = 5.7.
c. Death rate$^{(A-12)}$ = 2.4% of injuries.

(11) a. Days lost per death (assumed) = 6000 days/death.
b. Days lost per injury (assumed) = 229 days/injury.

(12) a. Land required for a 1000 MW power plant (assumed) = 800 acres.

(13) a. Efficiency of conventional boiler (assumed) = 37%.

TABLE A-11. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Boiler
Unit - 10^6 Btu (input)

Environmental Parameters	Fuel Input, Chemically Cleaned
Air	
NO_x, lb	0.75(1)
SO_2, lb	1.93(2)
CO, lb	0.042(3)
Particulate, lb	0.10(4)
Total organic material, lb	0.012(5)
Heat, 10^6 Btu	0.63(6)
Water	
Suspended solids, lb	0.025(7)
Dissolved solids, lb	0
Total organic material, lb	0.011(8)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	11.9(9)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	
Occupational Health	
Deaths	3.3×10^{-10}(10)
Total Injuries	1.4×10^{-8}(10)
Man Days Lost	5.1×10^{-6}(11)
Land Use, acre-hr/10^6 Btu	0.1(12)
Approx. Module Efficiency	37%(13)

Footnotes for Table A-11:

(1) a. NO_x emission factor$^{(A-1)}$ = 18 lb/ton coal burned.
b. Heating value of chemically cleaned coal = 12,000 Btu/lb.

(2) a. Sulfur content of eastern coal (assumed) = 3%.
b. Fraction of inorganic sulfur (assumed) 2.0%.
c. Removal efficiency (assumed) = 89% of inorganic sulfur.
d. Emission factor for $SO_2^{(A-1)}$ = 38 S lb/ton coal burned.
e. Sulfur content of chemically cleaned coal, S = 1.22%.

(3) a. CO emission factor$^{(A-1)}$ = 1 lb/ton coal burned.

(4) a. Ash content of coal, A (assumed) = 14.4%.
b. Particulate emission factor$^{(A-1)}$ = 16 A lb/ton coal burned.
c. Electrostatic precipitator efficiency (assumed) = 99%.

(5) a. Hydrocarbon emission factor$^{(A-1)}$ = 0.3 lb/ton coal burned.

(6) a. Efficiency of conventional boiler (assumed) = 37%.

(7) a. Total solid to water$^{(A-12)}$ = 0.036 lb/10^6 Btu.
b. Fraction of suspended solid (assumed) = 70%.

(8) a. Fraction of organic material in total solid (assumed) = 30%.

(9) a. Ash content of coal (assumed) = 14.4%.

(10) a. Man-hour required per 10^6 Btu for conventional power plant$^{(A-13)}$ = 2.4×10^{-3} man hour/10^6 Btu.
b. Total injuries per 10^6 man hour$^{(A-13)}$ = 5.7
c. Death rate$^{(A-12)}$ = 2.4% of injuries.

(11) a. Days lost per death (assumed) = 6000 days/death.
b. Days lost per injury (assumed) = 229 days/injury.

(12) a. Land required for a 1000 MW power plant (assumed) = 800 acres.

(13) a. Efficiency of conventional boiler (assumed) = 37%.

TABLE A-12. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Boiler
Unit - 10^6 Btu (input)

Environmental Parameters	Fuel Input, Solvent Refined Coal (Eastern)
Air	
NO_x, lb	0.56(1)
SO_2, lb	0.71(2)
CO, lb	0.037(3)
Particulate, lb	0.0003(4)
Total organic material, lb	0.01(5)
Heat, 10^6 Btu	0.63(6)
Water	
Suspended solids, lb	0.025(7)
Dissolved solids, lb	0
Total organic material, lb	0.011(8)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0.031(9)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	
Occupational Health	
Deaths	3.3×10^{-10}(10)
Total Injuries	1.4×10^{-8}(10)
Man Days Lost	5.1×10^{-6}(11)
Land Use, acre-hr/10^6 Btu	0.09(12)
Approx. Module Efficiency	37%(13)

Footnotes for Table A-12:

(1) a. NO_x emissions factor$^{(A-1)}$ = 18 lb/ton coal burned.
b. Heating value of solvent refined coal (SRC) (assumed) = 16000 Btu/lb.

(2) a. Sulfur content of solvent refined coal, S (assumed) = 0.6%.
b. SO_2 emission factor$^{(A-1)}$ = 38 S lb/ton coal burned.

(3) a. CO emission factor$^{(A-1)}$ = 1 lb/ton coal burned.

(4) a. Ash content of SRC, A (assumed) = 0.05%.
b. Particulate emission factor$^{(A-1)}$ = 16 A lb/ton coal burned.
c. Electrostatic precipitator efficiency (assumed) = 99%.

(5) a. Hydrocarbon emission factor$^{(A-1)}$ = 0.3 lb/ton coal burned.

(6) a. Efficiency of conventional boiler (assumed) = 37%.

(7) a. Total solid to water$^{(A-12)}$ = 0.036 lb/10^6 Btu.
b. Fraction of suspended solids (assumed) = 70%.

(8) a. Fraction of organic material in total solid (assumed) = 30%.

(9) a. Ash content of coal (assumed) = 0.05%.

(10) a. Man-hour required per 10^6 Btu for conventional power plant$^{(A-13)}$ = 2.4×10^{-3} man hour/10^6 Btu.
b. Total injuries per 10^6 man hour$^{(A-13)}$ = 5.7.
c. Death rate$^{(A-12)}$ = 2.4% of injuries.

(11) a. Days lost per death (assumed) = 6000 days/death.
b. Days lost per injuries (assumed) = 229 days/injury.

(12) a. Land requirement for a 1000 MW power plant (assumed) = 700 acres.

(13) a. Efficiency of conventional boiler (assumed) = 37%.

TABLE A- 13. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Boiler and Limestone Scrubbing
Unit - 10^6 Btu (input)

Environmental Parameters	Fuel Input, Coal, East
Air	
NO_x, lb	0.60(1)
SO_2, lb	0.50(2)
CO, lb	0.042(3)
Particulate, lb	0.1(4)
Total organic material, lb	0.013(5)
Heat, 10^6 Btu	0.65(6)
Water	
Suspended solids, lb	0.025(7)
Dissolved solids, lb	0
Total organic material, lb	0.011(8)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	2.4(9)
Sludge, lb	27.3(10)
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	3.3×10^{-10}(11)
Total Injuries	1.4×10^{-8}(11)
Man Days Lost	5.1×10^{-6}(12)
Land Use, acre-hr/10^6 Btu	0.1(13)
Approx. Module Efficiency	35%(14)

Footnotes for Table A-13:

(1) a. NO_x emission factor$^{(A-1)}$ = 18 lb/ton coal burned.
b. Heating value of eastern coal (assumed) = 12000 Btu/lb.
c. NO_x removal efficiency by limestone scrubber (assumed) = 20%.

(2) a. Sulfur content of eastern coal, S (assumed) = 3%.
b. SO_2 emission factor$^{(A-1)}$ = 38 S lb/ton coal burned.
c. Limestone scrubber efficiency (assumed) = 90%.

(3) a. CO emission factor$^{(A-1)}$ = 1 lb/ton coal burned.

(4) a. Ash content of eastern coal, A (assumed) = 14.4%.
b. Particulate emission factor$^{(A-1)}$ = 16 A lb/ton coal burned.
c. Scrubber efficiency for particulate removal (see App. S) = 99%.

(5) a. Hydrocarbon emission factor$^{(A-1)}$ = 0.3 lb/ton coal burned.

(6) a. Efficiency of conventional boiler with limestone scrubbing (assumed) = 35%.

(7) a. Total solid to water$^{(A-12)}$ = 0.036 lb/10^6 Btu.
b. Fraction of suspended solids (assumed) = 70%.

(8) a. Fraction of organic material in total solid (assumed) = 30%.

(9) a. Ash content of eastern coal (assumed) = 14.4%. 20% to bottom ash.

(10) a. Sulfur content of sludge (assumed) = 12%. Add fly ash collected.

(11) a. Man-hour required per 10^6 Btu for conventional power plant$^{(A-13)}$ = 2.4 x 10^{-3} man hour/10^6 Btu.
b. Total injuries per 10^6 Man hour$^{(A-13)}$ = 5.7.
c. Death rate$^{(A-12)}$ = 2.4% of injuries.

(12) a. Days lost per death (assumed) = 6000 days/death.
b. Days lost per injury (assumed) = 229 days/injury.

(13) a. Land requirement for a 1000 MW power plant (assumed) = 800 acres.

(14) a. Efficiency of conventional boiler with limestone scrubbing (assumed) = 35%.

TABLE A-14. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Boiler & MgO-Scrubbing
Unit - 10^6 Btu (Input)

Environmental Parameters	Input: Eastern Coal
Air	
NO_x, lb	0.60(1)
SO_2, lb	0.50(2)
CO, lb	0.042(3)
Particulate, lb	0.1(4)
Total organic material, lb	0.013(5)
Heat, 10^6 Btu	0.65(6)
Water	
Suspended solids, lb	0.025(7)
Dissolved solids, lb	0
Total organic material, lb	0.011(8)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	2.4(9)
Sludge, lb	0
Tailings, lb	10.4(10)
Hazardous, lb	0
By-Products	6.13(11)
Occupational Health	
Deaths	3.3×10^{-10}(12)
Total Injuries	1.4×10^{-8}(12)
Man Days Lost	5.1×10^{-6}(13)
Land Use, acre-hr/10^6 Btu	0.1(14)
Approx. Module Efficiency	35%(15)

Footnotes for Table A-14:

(1) a. NO_x emission factor$^{(A-1)}$ = 18 lb/ton coal burned.
  b. Heating value of eastern coal (assumed) = 12,000 Btu/lb.
  c. NO_x removal efficiency by MgO-scrubber (assumed) = 20%.

(2) a. Sulfur content of eastern coal, S (assumed) = 3%.
  b. SO_2 emission factor$^{(A-1)}$ = 38 S lb/ton coal burned.
  c. MgO-scrubber efficiency (assumed) = 90%.

(3) a. CO emission factor$^{(A-1)}$ = 1 lb/ton coal burned.

(4) a. Ash content of eastern coal, A (assumed) 14.4%.
  b. Particulate emission factor$^{(A-1)}$ = 16 A lb/ton coal burned.
  c. Scrubber efficiency for particulate removal (see App. S) = 99%.

(5) a. Hydrocarbon emission factor$^{(A-1)}$ = 0.3 lb/ton coal burned.

(6) a. Efficiency of conventional boiler with MgO-scrubbing (assumed) = 35%.

(7) a. Total solid to water$^{(A-12)}$ = 0.036 lb/10^6 Btu.
  b. Fraction of suspended solids (assumed) = 70%.

(8) a. Fraction of organic material in total solid (assumed) = 30%.

(9) a. Ash content of eastern coal (assumed) = 14.4%. 20% to bottom ash.

(10) a. MgO reacts with SO_2 to product 80% of $MgSO_3 \cdot 6H_2O$ and 20% of $MgSO_4 \cdot 7H_2O$ (assumption).
  b. 1% blowdown of $MgSO_3 \cdot 6H_2O$ and $MgSO_4 \cdot 7H_2O$ (assumed).
  c. Loss in regeneration (assumed) = 5%. Add fly ash collected.

(11) a. Sulfur reacted with MgO is regenerated in the form of H_2SO_4.
  b. Regeneration efficiency (assumed) = 100%.

(12) a. Man-hour required per 10^6 Btu for conventional power plant$^{(A-13)}$ = 2.4×10^{-3} man-hour/10^6 Btu.
  b. Total injuries per 10^6 man hour$^{(A-13)}$ = 5.7.
  c. Death rate$^{(A-12)}$ = 2.4% of injuries.

(13) a. Days lost per death (assumed = 6000 days/death.
  b. Days lost per injury (assumed) = 229 days/injury.

(14) a. Land requirement for a 1000 MW power plant (assumed) = 800 acres.

(15) a. Efficiency of conventional boiler with MgO-scrubbing (assumed) = 35%.

TABLE A-15. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Boiler (Limestone Scrubb)
Unit - 10^6 Btu (input)

Environmental Parameters	Fuel Input, Coal, West
Air	
NO_x, lb	0.78(1)
SO_2, lb	0.16(2)
CO, lb	0.054(3)
Particulate, lb	0.07(4)
Total organic material, lb	0.016(5)
Heat, 10^6 Btu	0.65(6)
Water	
Suspended solids, lb	0.025(7)
Dissolved solids, lb	0
Total organic material, lb	0.011(8)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	1.8(9)
Sludge, lb	13.4(10)
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	3.3×10^{-10}(11)
Total Injuries	1.4×10^{-8}(11)
Man Days Lost	5.1×10^{-6}(12)
Land Use, acre-hr/10^6 Btu	0.1(13)
Approx. Module Efficiency	35%(14)

Footnotes for Table A-15:

(1) a. NO_x emission factor(A-1) = 18 lb/ton coal burned.
    b. Heating value of western coal (assumed) = 9200 Btu/lb.
    c. NO_x removal efficiency by limestone scrubber (assumed) = 20%.

(2) a. SO_2 emission factor = 38 S lb/ton coal burned.
    b. Sulfur content of western coal, S (assumed) = 0.8%.
    c. Limestone scrubber efficiency (assumed) = 90%.

(3) a. CO emission factor(A-1) = 1 lb/ton coal burned.

(4) a. Particulate emission factor(A-1) = 16 A lb/ton coal burned.
    b. Ash content of western coal, A (assumed) = 8.4%.
    c. Scrubber efficiency for particulate removal (see App. S) = 99%.

(5) a. Hydrocarbon emission factor(A-1) = 0.3 lb/ton coal burned.

(6) a. Efficiency of conventional boiler with limestone scrubbing (assumed) = 35%.

(7) a. Total solid to water(A-12) = 0.036 lb/10^6 Btu.
    b. Fraction of suspended solids (assumed) = 70%.

(8) a. Fraction of organic material in total solid (assumed) = 30%.

(9) a. Ash content of western coal (assumed) = 8.4%. 20% to bottom ash.

(10) a. Sulfur content of sludge (assumed) = 12%. Add fly ash collected.

(11) a. Man-hour required per 10^6 Btu for conventional power plant(A-13) = 2.4×10^{-3} man hour/10^6 Btu.
    b. Total injuries per 10^6 man hour(A-13) = 5.7.
    c. Death rate(A-12) = 2.4% of injuries.

(12) a. Days lost per death (assumed) = 6000 days/death.
    b. Days lost per injury (assumed) = 229 days/injury.

(13) a. Land requirement for a 1000 MW power plant (assumed) = 800 acres.

(14) a. Efficiency of conventional boiler with limestone scrubbing (assumed) = 35%.

TABLE A-16. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Boiler - Limestone Scrubbing
Unit - 10^6 Btu (Input)

Environmental Parameters	Fuel Input, Physically Cleaned Coal, East
Air	
NO_x, lb	0.55(1)
SO_2, lb	0.2(2)
CO, lb	0.038(3)
Particulate, lb	0.044(4)
Total organic material, lb	0.011(5)
Heat, 10^6 Btu	0.65(6)
Water	
Suspended solids, lb	0.025(7)
Dissolved solids, lb	0
Total organic material, lb	0.011(8)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	1.1(9)
Sludge, lb	11.9(10)
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	3.3×10^{-10}(11)
Total Injuries	1.4×10^{-8}(11)
Man Days Lost	5.1×10^{-6}(12)
Land Use, acre-hr/10^6 Btu	0.1(13)
Approx. Module Efficiency	35%(14)

Footnotes for Table A-16:

(1) a. NO_x emission factor$^{(A-1)}$ = 18 lb/ton coal burned.
b. Heating value of physically cleaned coal = 13,180 Btu/lb.
c. NO_x removal efficiency by limestone scrubber (assumed) = 20%.

(2) a. Sulfur content of physically cleaned coal, S (assumed) = 1.4%.
b. Emission factor for $SO_2$$^{(A-1)}$ = 38 S lb/ton coal burned.
c. Limestone scrubber removal efficiency (assumed) = 90%.

(3) a. CO emission factor$^{(A-1)}$ = 1 lb/ton coal burned.

(4) a. Ash content of physically cleaned coal, A (assumed) = 7.2%.
b. Particulate emission factor$^{(A-1)}$ = 16A lb/ton coal burned.
c. Scrubber efficiency for particulate removal (see App. S) = 99%.

(5) a. Hydrocarbon emission factor$^{(A-1)}$ = 0.3 lb/ton coal burned.

(6) a. Efficiency of conventional boiler with limestone scrubbing (assumed) = 35%.

(7) a. Total solid to water$^{(A-12)}$ = 0.036 lb/10^6 Btu.
b. Fraction of suspended solids (assumed) = 70%.

(8) a. Fraction of organic material in total solids (assumed) = 30%.

(9) a. Ash content of physically cleaned coal (assumed) = 7.25%.
20% to bottom ash.

(10) a. Sulfur content of sludge (assumed) = 12%. Add particulate collected.

(11) a. Man hour required per 10^6 Btu for conventional power plant$^{(A-13)}$ = 2.4×10^{-3} man hour/10^6 Btu.
b. Total injuries per 10^6 man hours$^{(A-13)}$ = 5.7.
c. Death rate$^{(A-12)}$ = 2.4% of injuries.

(12) a. Days lost per death (assumed) = 6000 days/death.
b. Days lost per injury (assumed) = 229 days/injury.

(13) a. Land requirement for a 1000 MW power plant (assumed) = 800 acres.

(14) a. Efficiency of conventional boiler with limestone scrubbing (assumed) = 35%.

TABLE A- 17. ENVIRONMENTAL DATA FOR MODULE

Module - Lurgi Gasifier and Conventional Boiler
Unit - 10^6 Btu (input to conventional boiler)

Environmental Parameters	Fuel Input, Coal, East
Air	
NO_x, lb	0.40(1)
SO_2, lb	0.93(2)
CO, lb	0
Particulate, lb	0.015(3)
Total organic material, lb	0.11(4)
Heat, 10^6 Btu	0.92(5)
Water	
Suspended solids, lb	0.016(6)
Dissolved solids, lb	0
Total organic material, lb	0.002(7)
Heat, 10^6 Btu	Negligible after cooling tower
Phenols, lb	0.0029(8)
Solid	
Slag, lb	0
Ash, lb	9.82(9)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	1.9(10)
Occupational Health	
Deaths	1.5×10^{-9}(11)
Total Injuries	3.6×10^{-8}(12)
Man Days Lost	9.4×10^{-6}(13)
Land Use, acre-hr/10^6 Btu	0.12(14)
Approx. Module Efficiency	25.9%(15)

Footnotes for Table A-17:

(1) a. NO_x comes from gas-fired boiler in gasifier plant and gas-fired power plant.
b. NO_x emission factor$^{(A-1)}$ = 0.39 lb/10^6 Btu for natural gas.
c. The emission factor is value for Lurgi gas combustion on the basis of heating value (assumed).

(2) a. Basis: 1000 MW nominal cogas power plant.$^{(A-6)}$
b. Coal input rate$^{(A-6)}$ = 341 tons/hr.
c. SO_2 emission comes from gas-fired boiler in gasifier plant and gas-fired power plant.$^{(A-6)}$
d. 1% of sulfur lost to atmosphere from gasifier plant by leaking (assumption).
e. Content of H_2S in Lurgi gas produced$^{(A-6)}$ = 0.105% by volume.
f. Lurgi gas production rate from the plant = 112600 lb-moles/hr.

(3) a. Particulate emission comes from gas-fired power plant (assumed).
b. Emission factor for natural gas$^{(A-1)}$ = 0.015 lg/10^6 Btu.
c. Assumed that the emission factor for natural gas combustion is valid to Lurgi gas combustion on the basis of heating value.

(4) a. 1% of total organic matter (COS and CH_4) is lost from gasifier by leaking (assumed).

(5) a. 63% of the total input energy to gas-fired power plant is lost to atmosphere (based on the assumed efficiency of the power plant).
b. Efficiency of Lurgi gasifier plant (assumed) - 70%.
c. Efficiency loss due to material loss in Lurgi gasifier plant (assumed) = 10%.

(6) a. Suspended solid emission comes from gas-fired power plant (assumed).
b. Emission from a 1000 MW plant$^{(A-12)}$ = 548 tons.

(7) a. Total organic material comes from gas-fired power plant (assumed).
b. Emission factor$^{(A-12)}$ = 73 tons/year for a 1000 MW plant.

(8) a. From data supplied by T. K. Janes, EPA.

(9) a. Ash content of coal (assumed) = 14.4%.

(10) a. The by-product of Lurgi gasifier plant is sulfur from Claus unit.

(11) a. Injuries are combined for Lurgi gasifier plant and gas-fired power plant operations.
b. 40 men operate a 500-ton coal/hr capacity Lurgi gasifier plant (assumed).
c. Using chemical industry data, injuries per man-hour$^{(A-5)}$ = 8.1 injuries/10^6 man-hours.
d. Death rate (assumed) = 5% of total injuries.
e. Death attributed to a 1000 MW gas-fired power plant$^{(A-12)}$ = 0.01 death/year.

(12) a. Injuries attributed to a 1000 MW gas-fired power plant$^{(A-12)}$ = 0.6 injuries/year.

(13) a. Using chemical industry data, days lost per man-hour$^{(A-5)}$ = 528 days/10^6 man-hours.
b. Man-days lost per death (assumed) = 6000 days/death
c. Man-days lost attributed to a 1000 MW gas-fired power plant$^{(A-13)}$ = 197 man days/year.

(14) a. Land requirement for a 1000 MW coal-fired power plant (assumed) = 800 acres.
b. Additional land requirement for Lurgi gasifier plant (assumed) = 150 acres.

(15) a. Efficiency of Lurgi gasifier plant (assumed) = 70%.
b. Efficiency of gas-fired power plant (assumed) = 37%.

TABLE A-18. ENVIRONMENTAL DATA FOR MODULE

Module - Hygas (Gasification of Coal-High Btu)
Unit - 10^6 Btu (output)

Environmental Parameters	Fuel Input, Coal, East
Air	
NO_x, lb	0.25(1)
SO_2, lb	0.55(2)
CO, lb	0
Particulate, lb	0.12(3)
Total organic material, lb	0.0014(4)
Heat, 10^6 Btu	0.34(5)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible after cooling tower
Phenols, lb	4.6×10^{-5}(6)
Solid	
Slag, lb	0
Ash, lb	6.7(7)
Sludge, lb	25.8(8)
Tailings, lb	0
Hazardous, lb	0
By-Products	2.0(9)
Occupational Health	
Deaths	5×10^{-9}(10)
Total Injuries	1.7×10^{-7}(10)
Man Days Lost	4.6×10^{-5}(11)
Land Use, acre-hr/10^6 Btu	0.02(12)
Approx. Module Efficiency	66%(13)

Footnotes for Table A-18.

(1) a. NO_x emission comes from a 110 MW power plant in the Hygas plant.
b. NO_x emission factor (assumed) = 0.72 lb/10^6 Btu generated by the power plant.
c. Hygas plant capacity(A-6) = 80 x 10^6 scfd.
d. Heating value of gas produced(A-6) = 950 Btu/ft^3.

(2) a. SO_2 emission comes from two limestone scrubbers.
b. Sulfur from limestone scrubbers(A-6) = 1300 lb/hr.
c. Sulfur content of coal used in this calculation (assumed)=3%.
d. Adjustment factor for sulfur content(A-6) = 0.68.

(3) a. Ash content of coal used in this calculation (assumed) = 14.4%.
b. Adjustment factor for ash content(A-6) = 1.31.
c. 65% of total ash goes to scrubber as particulate (assumed).
d. Limestone scrubber efficiency for removal of particulate (assumed) = 99%.

(4) a. Hydrocarbon emission comes from a 110 MW power plant.
b. Hydrocarbon emission factor (assumed) = 0.04 lb/10^6 Btu.

(5) a. Efficiency of Hygas plant(A-6) = 66%.

(6) a. Assumed to be same as for CO_2 acceptor (see CO_2 Acceptor for the detail).

(7) a. Ash comes from boiler (bottom ash).

(8) a. Sulfur from limestone scrubbers(A-6) = 7600 lb/hr.
b. Sulfur content of sludge = 12%.
c. Adjustment factor for sulfur content in fuel(A-6) = 0.68.
d. Sludge comes from limestone scrubbers (limestone slurry plus particulate collected).

(9) a. Elemental sulfur from Claus plant is the sole by-product (assumed).
b. Adjustment factor for sulfur content in coal = 0.68.

(10) a. Man-hours required for a 1x10^{10} Btu/hr capacity Hygas plant (assumed) = 4000 man hours/day.
b. Injury rate (assumed) = 10 injuries/10^6 man hours.
c. 3% of injury assumed fatal.

(11) a. Man-days lost per death (assumed) = 6000 days/death.
b. Man-days lost per injury (assumed) = 95 days/injury.

(12) a. Personal communication with EPA.

(13) a. Reported by Processes Research.(A-6)

TABLE A-19. ENVIRONMENTAL DATA FOR MODULE

Module - CO_2 Acceptor (Gasification-High Btu)
Unit - 10^6 Btu (output)

Environmental Parameters	Fuel Input, Lignite
Air	
NO_x, lb	0
SO_2, lb	1.0(1)
CO, lb	0
Particulate, lb	0.02(2)
Total organic material, lb	0
Heat, 10^6 Btu	0.38(3)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible after cooling tower
Phenols, lb	4.6×10^{-5}(4)
Solid	
Slag, lb	0
Ash, lb	39.9(5)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	1.8(6)
Occupational Health	
Deaths	5×10^{-9}(7)
Total Injuries	1.7×10^{-7}(7)
Man Days Lost	4.6×10^{-5}(8)
Land Use, acre-hr/10^6 Btu	0.02(9)
Approx. Module Efficiency	62%(10)

Footnotes for Table A-19:

(1) a. SO_2 emission comes from lignite dryer, regenerator and Claus unit$^{(A-6)}$.
- b. SO_2 from lignite dryer$^{(A-6)}$ = 3600 lb/hr.
- c. SO_2 from regenerator off-gas$^{(A-6)}$ = 2400 lb/hr.
- d. SO_2 from Claus unit$^{(A-6)}$ = 120 lb/hr.
- e. CO_2 Acceptor plant capacity = 10,400 x 10^6 Btu/hr.
- f. Lignite sulfur content (assumed) = 1%.
- g. Adjustment factor for sulfur$^{(A-6)}$ = 1.7.

(2) a. Fly ash from lignite dryer$^{(A-6)}$ = 16,000 lb/hr.
- b. Ash content of lignite in this calculation (assumed) = 10%.
- c. Adjustment factor for ash(A-6) = 1.4.
- d. Efficiency of electrostatic precipitator (assumed) = 99%.

(3) a. Efficiency of the plant = 62% (personal communication with T. K. Janes of EPA).

(4) a. Total wastewater from spray tower acid gas remover, and compressor$^{(A-6)}$ = 481,500 lb/hr.
- b. Phenol concentration (assumed) = 1 ppm.

(5) a. Ash from acceptor stripper$^{(A-6)}$ = 154,000 lb/hr.
- b. Acceptor from acceptor stripper$^{(A-6)}$ = 60,000 lb/hr.
- c. Adjustment factor for ash(A-6) = 1.4.
- d. Adjustment factor for acceptor$^{(A-6)}$ = 1.7.
- e. Fly ash collected from precipitator = 2.13 lb/10^6 Btu.

(6) a. Elemental sulfur from Claus unit$^{(A-6)}$ = 10,840 lb/hr.
- b. Adjustment factor for sulfur$^{(A-6)}$ = 1.7.

(7) a. Man hours required for a 1 x 10^{10} Btu/hr capacity CO_2 acceptor plant (assumed) = 4000 man hours/day.
- b. Injury rate (assumed) = 10 injuries/10^6 man hours.
- c. 3% of injury assumed fatal.

(8) a. Man days lost per death (assumed) = 6000 days/death.
- b. Man days lost per injury (assumed) = 95 days/injury.

(9) a. Personal communication with EPA.

(10) a. Personal communication with T. K. Janes of EPA.

TABLE A-20. ENVIRONMENTAL DATA FOR MODULE

Module - Molten Iron Combustion Plus Conventional Boiler
Unit - 10^6 Btu (input to boiler)

Environmental Parameters	Fuel Input, Coal, East
Air	
NO_x, lb	0.39(1)
SO_2, lb	0.017(2)
CO, lb	0
Particulate, lb	0.034(3)
Total organic material, lb	0.04(4)
Heat, 10^6 Btu	0.65(5)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	10(6)
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	3.1 Processes Research Report
Occupational Health	
Deaths	1.5×10^{-9}(7)
Total Injuries	3.6×10^{-8}(8)
Man Days Lost	9.4×10^{-6}(9)
Land Use, acre-hr/10^6 Btu	0.12(10)
Approx. Module Efficiency	35%(11)

Footnotes for Table A-20:

(1) a. NO_x emission comes from burning of product gas in a conventional boiler (assumed).
b. NO_x emission factor for product gas (assumed) = 390 $lb/10^6\ ft^3$.
c. Heating value of product gas (assumed) = 1000 Btu/ft^3.

(2) a. SO_2 from conventional boiler(A-6) = 142 lb/hr.
b. Capacity of power plant(A-6) = 1000 MW
c. SO_2 from Claus unit(A-6) = 60 lb/hr.
d. Adjustment factor for sulfur = 0.833 (i.e., $\frac{3.0}{3.6}$)

(3) a. Assume 0.02 gr/ft^3 of particulate in exit gas.
b. Stack gas flow rate (assumed) = 2000 ft^3/MW-min.

(4) a. Hydrocarbon emission for burning product gas (assumed) = 40 $lb/10^6\ ft^3$.

(5) a. Approximate module efficiency (assumed) = 35%.

(6) a. Slag from slag desulfurizer(A-6) = 120,000 lb/hr.
b. Adjustment factor for slag(A-6) = 0.833.

(7) a. Injuries result from gasification plant and gas fired power plant operations.
b. 40 men operate a 500 ton coal/hr capacity gasification plant assumed).
c. Using chemical industry data, injuries per man hour(A-5) = 8.1 injuries/10^6 man hours.
d. Death rate of the injury (assumed) = 5%.
e. Death attributed to a 1000 MW gas fired power plant(A-12) = 0.01 deaths/year.

(8) a. Injuries attributed to a 1000 MW gas fired power plant(A-12) = 0.6 injuries/year.

(9) a. Using chemical industry data, days lost per man hour(A-5) = 528 days/10^6 man hours.
b. Man days lost per death (assumed) = 6000 days/death.
c. Man days lost attributed to a 1000 MW gas fired power plant(A-12) = 197 man days/year.

(10) a. Land requirement for a 1000 MW coal fired power plant (assumed) = 800 acres.
b. Additional land requirement for gasification plant (assumed) = 150 acres.

(11) a. Efficiency of gasification plant (assumed) = 95%.
b. Efficiency of gas fired power plant (assumed) = 37%.

TABLE A- 21. ENVIRONMENTAL DATA FOR MODULE

Module - Crude Oil Gasification
Unit - 10^6 Btu (output)

Environmental Parameters	Fuel Input, Crude Oil
Air	
NO_x, lb	0.08(1)
SO_2, lb	0.03-0.05(2)
CO, lb	Negligible
Particulate, lb	0.002(3)
Total organic material, lb	0.004(4)
Heat, 10^6 Btu	0.3(5)
Water	
Suspended solids, lb	--
Dissolved solids, lb	0.02(6)
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	--
Solid	
Slag, lb	--
Ash, lb	0.06-0.12(7)
Sludge, lb	0.06-0.12(8)
Tailings, lb	--
Hazardous, lb	--
By-Products	1.3-2.5(9)
Occupational Health	
Deaths	Not determined
Total Injuries	Not determined
Man Days Lost	Not determined
Land Use, acre-hr/10^6 Btu	0.03-0.05(10)
Approx. Module Efficiency	77%(11)

Footnotes for Table A-21:

(1) a. Plant efficiency of crude oil SNG plant (assumed) = 77%.
b. 23% of input is consumed as liquid fuel for plant operation (assumed).
c. NO_x emission factor$^{(A-1)}$ = 40 lb/10^3 gal.
d. Heating value of input crude = 6.3 x 10^6 Btu/barrel (assumed).

(2) a. Sulfur content of crude oil (assumed) = 2 to 4%.
b. Sulfur removal efficiency of Claus plant and tail gas treatment (assumed) = 99%.
c. Density of crude oil - 7.3 lb/gal.

(3) a. Particulate emission factor for fluid catalytic cracking unit$^{(A-1)}$ = 61 lb/10^3 bbl fresh feed.
b. Fraction of fresh feed to be cracked in this process (assumed) = 1/3.
c. Particulate removal efficiency of cyclone (assumed) = 50%.

(4) a. Losses of crude oil to atmosphere (assumed) = 20 lb/10^3 bbl input.

(5) a. 23% of input fuel is consumed for plant operation (assumed).

(6) a. Salt content of crude oil (assumed) = 100 lb/10^3 bbl.

(7) a. Solid waste from spent catalyst not worth reclaiming (assumed) = 300 to 600 lb/10^3 bbl.

(8) a. Sludges from water treatment (assumed) = 300 to 600 lb/10^3 bbl.

(9) a. By-product is sulfur. Quantity derived from assumed sulfur content of input crude (2 to 4%) and 99% recovery in Claus unit and tail-gas treatment.

(10) a. Land required for a 100,000 bbl/day plant (assumed) = 600 to 1000 acres.

(11) a. Efficiency of plant (assumed) = 77%.

TABLE A-22. ENVIRONMENTAL DATA FOR MODULE

Module - Fluid-Bed Combustion Plus Combined Cycle
Unit - 10^6 Btu (input to combustion cycle)

Environmental Parameters	Fuel Input, Coal, East
Air	
NO_x, lb	0.14(1)
SO_2, lb	0.7(2)
CO, lb	0
Particulate, lb	0.02(3)
Total organic material, lb	0
Heat, 10^6 Btu	0.62(4)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	17.3(5)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	1.9(6)
Occupational Health	
Deaths	1.5×10^{-9}(7)
Total Injuries	3.6×10^{-8}(8)
Man Days Lost	1.4×10^{-5}(9)
Land Use, acre-hr/10^6 Btu	0.12(10)
Approx. Module Efficiency	38%(11)

Footnotes for Table A-22:

(1) a. Average value of 0.07 and 0.22 lb/10^6 Btu reported in Westinghouse Report.(A-23)

(2) a. SO_2 emission factor reported(A-23) = 1 lb/10^6 Btu.
b. Adjustment factor for sulfur content(A-23) = 0.7 (i.e., $\frac{3.0}{4.3}$).

(3) a. Particulate emission factor reported(A-23) = 0.02 lb/10^6 Btu.

(4) a. Efficiency of the module (assumed) = 38%.

(5) a. Ash content of eastern coal (assumed) = 14.4%.
b. Heating value of coal (assumed) = 24 x 10^6 Btu/ton.
c. Limestone requirement per pound of sulfur = 1.75 lb.

(6) a. The sole by-product is elemental sulfur.
b. Sulfur content of coal (assumed) = 3%.
c. 90% of sulfur is collected by limestone (assumed).
d. Sulfur loss from Claus unit(A-23) = 0.35 lb/10^6 Btu.

(7) a. Injuries calculated from fluid-bed combustion plant and gas-fired power plant operations.
b. 40 men operate a 500 ton coal/hr capacity combustion plant (assumed).
c. Using chemical industry data for gasification plant, injuries per man hour(A-5) = 8.1 injuries/10^6 man hours.
d. Death rate (assumed) = 5% of injuries.
e. Death attributed to a 100 MW gas-fired power plant(A-12) = 0.01 deaths/year.

(8) a. Injuries attributed to a 1000 MW gas fired power plant(A-12) = 0.6 injuries/year.

(9) a. Using chemical industry data for gasification plant, man-days lost per man hour(A-5) = 528 days/10^6 man hours.
b. Man days lost per death (assumed) = 6000 days/death.
c. Man days lost attributed to a 1000 MW gas fired power plant(A-12) = 197 man-days/year.

(10) a. Land requirement for a 1000 MW coal fired power plant (assumed) = 800 acres.
b. Additional land requirement for fluid-bed combustion unit (assumed) = 150 acres.

(11) a. Efficiency(A-23) = 38%.

TABLE A- 23. ENVIRONMENTAL DATA FOR MODULE

Module - CAFB Boiler (Residual Oil) + Combined Cycle
Unit - 10^6 Btu (input)

Environmental Parameters	Fuel Input, Residual Oil (Imported)
Air	
NO_x, lb	0.16(1)
SO_2, lb	0.45(2)
CO, lb	0
Particulate, lb	0.01(3)
Total organic material, lb	0.04(4)
Heat, 10^6 Btu	0.62(5)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	3.0(6)
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	1.4(7)
Occupational Health	
Deaths	2×10^{-9}(8)
Total Injuries	7×10^{-8}(8)
Man Days Lost	1.7×10^{-5}(9)
Land Use, acre-hr/10^6 Btu	0.06(10)
Approx. Module Efficiency	38%(11)

Footnotes for Table A-23:

(1) a. Experimental data obtained by Westinghouse.(A-23)

(2) a. SO_2 from boiler(A-23) = 0.35 lb/10^6 Btu.
b. SO_2 from Claus unit(A-23) = 0.1 lb/10^6 Btu.

(3) a. Electrostatic precipitator is employed to control particulate emission (assumed).
b. Particulate emission factor(A-23) = 0.01 lb/10^6 Btu.

(4) a. Hydrocarbon emission factor for burning CAFB gas (assumed) = 40 lb/10^6 ft^3.

(5) a. Efficiency of the module (assumed) = 38%.

(6) a. Sulfur content of oil (assumed) = 3%.
b. Limestone requirement per pound of sulfur = 1.75 lb.
c. Heating value of oil (assumed) = 6.3 x 10^6 Btu/bbl.

(7) a. Sulfur content of oil (assumed) = 3%.
b. Sulfur emission = 0.225.

(8) a. Injury rate per man hour (assumed) = 10 injuries/10^6 man hours.
b. Death rate of injury = 3%.
c. 70 men operate a 1000 MW plant (assumed).

(9) a. Man days lost per death (assumed) = 6000 days/death.
b. Man days lost per injury (assumed) = 95 days/injury.

(10) a. Land requirement for a 1000 MW oil-fired power plant (assumed) = 300 acres.
b. Additional land requirement for CAFB gas unit (assumed) = 150 acres.

(11) a. Assumed efficiency = 38%.

TABLE A-24. ENVIRONMENTAL DATA FOR MODULE

Module - Gas Well
Unit - 10^6 Btu

Environmental Parameters	Fuel Input, Natural Gas
Air	
NO_x, lb	0.23(1)
SO_2, lb	0
CO, lb	0
Particulate, lb	0
Total organic material, lb	0.1(2)
Heat, 10^6 Btu	0
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	12.6(3)
Occupational Health	
Deaths	2.2×10^{-9}(4)
Total Injuries	2.1×10^{-7}(5)
Man Days Lost	3.5×10^{-5}(6)
Land Use, acre-hr/10^6 Btu	0.06(7)
Approx. Module Efficiency	96%(8)

Footnotes for Table A-24:

(1) a. Natural gas consumed to maintain pumping power in gas well(A-15 = 0.032 ft^3/ft^3 recovered.
b. NO_x emission factor(A-1) = 7.3 x 10^{-3} lb/ft^3 consumed.
c. Heating value of natural gas (assumed) = 1000 Btu/ft^3.

(2) a. Natural gas loss in gas well operation(A-15) = 0.0022 ft^3/ft^3 recovered.
b. Density of natural gas = 0.045 lb/ft^3.

(3) a. Hydrocarbon recovered (liquid phase)(A-15) = 0.047 ft^3 (equivalent gas volume)/ft^3 recovered.
b. The hydrocarbon is assumed as heptane (Molecular weight = 96).

(4) a. Total number of fatal injuries in oil and gas production(A-17, (A-19) = 95.
b. Total energy from oil and gas production(A-17, A-18) = 43 x 10^{15} Btu.

(5) a. Total number of nonfatal injury in oil and gas production in 1969(A-17, A-19) = 9023.

(6) a. Total man-days lost in oil and gas production in 1969(A-17, (A-19) = 1.49 x 10^6 man-days.

(7) a. Land requirement for gas well is assumed to be the same as that for oil well.

b. Land use for oil well (see Table A-36) = 0.06 acre-hour/10^6 Btu.

(8) a. Efficient (assumed) = 96%.

TABLE A-25 ENVIRONMENTAL DATA FOR MODULE

Module - Removal of Sulfur from Natural Gas
Unit - 10^6 Btu (output)

Environmental Parameters	Fuel Input, Natural Gas
Air	
NO_x, lb	Nil
SO_2, lb	0.025(1)
CO, lb	Nil
Particulate, lb	Nil
Total organic material, lb	Nil
Heat, 10^6 Btu	Nil
Water	
Suspended solids, lb	Nil
Dissolved solids, lb	Nil
Total organic material, lb	Nil
Heat, 10^6 Btu	Nil
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	Nil
Ash, lb	Nil
Sludge, lb	Nil
Tailings, lb	Nil
Hazardous, lb	Nil
By-Products	0.24(2)
Occupational Health	Not determined
Deaths	Not determined
Total Injuries	Not determined
Man Days Lost	Not determined
Land Use, acre-hr/10^6 Btu	0.005(3)
Approx. Module Efficiency	100%(4)

Footnotes for Table A-25:

(1) a. Table K-2 (Appendix K) gives the following 1970 data from 6 states:
SO_2 in Claus plants tail gas at 90% eff. = 441 T/D
SO_2 purged from plants not recovering sulfur = 2,335 T/D
Total gas production = 26.76×10^9 ft^3/d.
b. Assume 95% efficiency for Claus plants applied to all sour gas treatment plants, then:

$$\frac{(441/0.1 + 2335) \text{ ton } SO_2/\text{day} \times .05 \times 2000 \text{ lb/ton}}{26.76 \times 10^9 \text{ ft}^3/\text{day} \times 10^3 \text{ Btu/ft}^3} = 0.025 \frac{\text{lb } SO_2}{10^6 \text{ Btu}}$$

(2) a. at 95% efficiency for the Claus plants, the amount of SO_2 converted to sulfur is 19 times the amount of SO_2 emitted. Therefore, the amount of by-product sulfur produced is:

$$.025 \text{ lb } SO_2 \text{ emitted} \times 19 \times \frac{32 \text{ lb S}}{64 \text{ lb } SO_2} = 0.24 \text{ lb S}$$

(3) a. Land requirement for a 100 million ft^3/day plant (assumed) = 20 acres.

(4) a. Energy requirements for desulfurization process were not determined.

TABLE A-26. ENVIRONMENTAL DATA FOR MODULE

Module -- Gas Pipeline
Unit -- 10^6 Btu

Environmental Parameters	Fuel Input, Natural Gas
Air	
NO_x, lb	0.304$^{(1)}$
SO_2, lb	0
CO, lb	0
Particulate, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	
Occupational Health	
Deaths	Not determined
Total Injuries	Not determined
Man Days Lost	Not determined
Land Use, acre-hr/10^6 Btu	1.0$^{(2)}$
Approx. Module Efficiency	95.9%$^{(3)}$

Footnotes for Table A-26:

(1) a. Natural gas consumed to maintain a compressor at 750 psia(A-15) = 0.042 ft^3/ft^3 transmitted.
b. NO_x emission factor for running gas engines(A-1) = 7300 lb/10^6 ft^3 burned.

(2) a. Land requirement for pipelines to run a 1000 MW Power Plant (A-12) = 213 acres.

(3) a. Efficiency (assumed) = 95.9%.

TABLE A-27. ENVIRONMENTAL DATA FOR MODULE

Module -- Underground Gas Storage
Unit -- Output 10^6 Btu

Environmental Parameters	Fuel Input, Natural Gas
Air	
NO_x, lb	0.06(1)
SO_2, lb	0
CO, lb	0
Particulate, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
	0
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	
Occupational Health	
Deaths	Not determined
Total Injuries	Not determined
Man Days Lost	Not determined
Land Use, acre-hr/10^6 Btu	
Approx. Module Efficiency	100%(2)

Footnotes for Table A-27:

(1) a. Natural gas burned to compress 1 scf of natural gas from 550 psi to 1800 psi with 25% efficiency = 0.014 ft^3.
b. NO_x emission factor for running gas engines$^{(A-15)}$ = 4300 lb/10^6 ft^3.

(2) a. Efficiency of storage operation (assumed) = 100%.

TABLE A-28. ENVIRONMENTAL DATA FOR MODULE

Module -- Conventional Boiler
Unit -- 10^6 Btu (input)

Environmental Parameters	Fuel Input, Natural Gas
Air	
NO_x, lb	0.39(1)
SO_2, lb	0.0006(2)
CO, lb	0.0004(3)
Particulate, lb	0.015(4)
Total organic material, lb	0.04(5)
Heat, 10^6 Btu	0.63(6)
Water	
Suspended solids, lb	0.016(7)
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	1.5×10^{-10}(8)
Total Injuries	8.9×10^{-9}(9)
Man Days Lost	2.9×10^{-6}(10)
Land Use, acre-hr/10^6 Btu	0.02(11)
Approx. Module Efficiency	37%(12)

Footnotes for Table A-28:

(1) a. NO_x emission factor$^{(A-1)}$ = 39 lb/10^6 ft^3 of natural gas.
b. Heating value of natural gas (assumed) = 1000 Btu/ft^3.

(2) a. SO_2 emission factor for burning natural gas = 0.6 lb/10^6 ft^3.

(3) a. CO emission factor for burning natural gas = 0.4 lb/10^6 ft^3.

(4) a. Particulate emission factor for burning natural gas = 15 lb/10^6 ft^3.

(5) a. Hydrocarbon emission factor for burning natural gas = 40 lb/10^6 ft^3.

(6) a. Efficiency of gas fired conventional boiler = 37%.

(7) a. Suspended solid emission from a 1000 MW gas fired Power Plant (A-12) = 548 tons.

(8) a. Deaths attributed to a 1000 MW gas fired Power Plant$^{(A-12)}$ = 0.01 death/year.

(9) a. Injuries attributed to a 1000 MW gas fired Power Plant$^{(A-12)}$ = 0.6 injuries/year.

(10) a. Man-days lost attributed to a 1000 MW gas fired Power Plant$^{(A-12)}$ = 197 man-days/year.

(11) a. Land requirement for a 1000 MW gas fired Power Plant$^{(A-12)}$ = 150 acres.

(12) a. Efficiency of gas fired Power Plant (assumed) = 37%.

TABLE A-29 ENVIRONMENTAL DATA FOR MODULE

Module - LNG Tanker
Unit - 10^6 Btu

Environmental Parameters	
Air	
NO_x, lb	Negligible
SO_2, lb	"
CO, lb	"
Particulate, lb	"
Total organic material, lb	"
Heat, 10^6 Btu	"
Water	
Suspended solids, lb	Nil
Dissolved solids, lb	Nil
Total organic material, lb	Nil
Heat, 10^6 Btu	Not applicable
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	Nil
Ash, lb	Negligible
Sludge, lb	Nil
Tailings, lb	Nil
Hazardous, lb	Nil
By-Products	Nil
Occupational Health	Usual maritime, fire asphyxiation
Deaths	Not determined
Total Injuries	Not determined
Man Days Lost	Not determined
Land Use, acre-hr/10^6 Btu	None
Approx. Module Efficiency	97%(1)

Footnote for Table A-29:

(1) a. Efficiency of LNG tanker (assumed) = 97% based on use of boil-off gas as fuel at the rate of 0.3% of the cargo per day for an average trip of 10 days. Supplemental use of fuel oil as fuel is not included.

TABLE A-30 ENVIRONMENTAL DATA FOR MODULE

Module - LNG Port Facilities
Unit - 10^6 Btu
(Exclusive of storage or gasification)

Environmental Parameters	Fuel Input, Natural Gas
Air	
NO_x, lb	0
SO_2, lb	0
CO, lb	0
Particulate, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	Fire, asphyxiation
Deaths	Not determined
Total Injuries	Not determined
Man Days Lost	Not determined
Land Use, acre-hr/10^6 Btu	Very small(1)
Approx. Module Efficiency	100%(2)

Footnotes for Table A-30:

(1) Land use required by port facilities is small compared to storage tanks and gasification facilities.

(2) Energy requirements and gas losses are minimal compared with total throughput.

TABLE A-31. ENVIRONMENTAL DATA FOR MODULE

Module - LNG Storage
Unit - 10^6 Btu

Environmental Parameters	Fuel Input, Natural Gas
Air	
NO_x, lb	0
SO_2, lb	0
CO, lb	0
Particulate, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	Fire, asphyxiation
Deaths	Not determined
Total Injuries	Not determined
Man Days Lost	Not determined
Land Use, acre-hr/10^6 Btu	0.002(1)
Approx. Module Efficiency	100%(2)

Footnotes for Table A-31:

(1) a. Approximately 200 million cubic feet of gas per day are required to fuel a 1000 MW power plant. A medium-sized tanker carries the equivalent of about 10^9 cubic feet of gas, or about 5 days supply. The equivalent liquid volume is 1.7 million cubic feet. A 50-foot deep tank of this volume would have a cross-sectional area of 0.78 acre.
b. The overall land requirement for the storage of LNG for a 1000 MW power plant is estimated to be 20 acres.

(2) a. Boil-off is compressed and added to the lines. The energy required is minimal.

TABLE A-32. ENVIRONMENTAL DATA FOR MODULE

Module - LNG Gasification
Unit - 10^6 Btu

Environmental Parameters	Fuel Input, Natural Gas
Air	
NO_x, lb	1.1×10^{-3} (1)
SO_2, lb	Nil
CO, lb	Nil
Particulate, lb	Nil
Total organic material, lb	Nil
Heat, 10^6 Btu	0
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	Fire, asphyxiation
Deaths	Not determined
Total Injuries	Not determined
Man Days Lost	Not determined
Land Use, acre-hr/10^6 Btu	Nil (2)
Approx. Module Efficiency	99% (3)

Footnotes for Table A-32:

(1) a. Heat of vaporization of liquified natural gas (assumed) = 220 Btu/lb
    b. Density of natural gas (assumed) = 0.045 lb/ft^3
    c. Heating value of natural gas (assumed = 1000 Btu/ft^3
    d. Efficiency of heating unit (assumed) = 90%
    e. NO_x emission factor for natural gas burning(A-1) = 100 lb/10^6/ft^3

(2) a. No additional land required for gasification.

(3) a. Heat requirement for vaporization (same gases as footnote 1) = 11000 Btu/10^6 Btu.

TABLE A-33. ENVIRONMENTAL DATA FOR MODULE

Module - Oil Shale Extraction and Processing
Unit - 10^6 Btu (output)

Environmental Parameters	Surface	Underground
Air		
NO_x, lb	0.025-0.038(1)	0.025-0.038
SO_2, lb	0.15 -0.22 (2)	0.15 -0.22
CO, lb	--	--
Particulate, lb	0.14(3)	0.14
Total organic material, lb	--	--
Heat, 10^6 Btu	--	--
Water		
Suspended solids, lb	--	--
Dissolved solids, lb	0.1(4)	0.1
Total organic material, lb	--	--
Heat, 10^6 Btu	Negligible	Negligible
Acid (H_2SO_4), lb	0	0
Solid		
Slag, lb	--	--
Ash, lb	--	--
Sludge, lb	--	--
Tailings, lb	370	370
Overburden, lb	180-1000(6)	Not determined
By-Products (Ammonia/Sulfur), lb	0.9/0.3(7)	0.9/0.3
Occupational Health		
Deaths	--	--
Total Injuries	--	--
Man Days Lost	--	--
Land Use, acre-hr/10^6 Btu	Not determined	Not determined
Approx. Module Efficiency	Not determined	Not determined

Footnotes for Table A-33:

(1) a. NO_x emission from a 10^6 bbl/day capacity oil shale processing unit(A-27) = 80 to 120 tons/day.
b. Heating value of oil (assumed) = 6.3×10^6 Btu/bbl.

(2) a. SO_2 emission from a 10^6 bbl/day capacity oil shale processing unit(A-27) = 460 to 680 tons/day.

(3) a. Particulate emission from a 10^6 bbl/day capacity oil shale operation(A-27) = 440 tons/day.
b. Assumes 98% primary dust capture efficiency.

(4) a. Volume of water discharged will be highly variable due to variations in mine water produced. Assume a discharge of 10^6 gal/day for a 10^5 bbl/day capacity oil shale operation.
b. Average salinity of the effluent from oil shale processing (assumed) = 740 mg/liter.

(5) a. From Figure D-2, Appendix D, spent shale and dust production from a 50,000 bbl/day capacity oil shale processing = 58,960 tons/day.

(6) a. The ratio of overburden oil shale seam thickness and quality is expected to vary widely. The following ranges were assumed: 235 feet of overburden with 450 feet of shale, and 450 feet of overburden with 150 feet of shale.
b. Assuming 30 gallons/ton shale with a density of 130 lb/ft^3, a 450 foot seam would yield approximately 900,000 bbl/acre and a 150 foot seam would yield approximately 300,000 bbl/acre.
c. Assume overburden density = 100 lb/ft^3.

(7) a. Ammonia production from a 50,000 bbl/day capacity oil shale processing(A-27) = 138 tons/day
b. Sulfur production from a 50,000 bbl/day capacity oil shale processing(A-27) = 43 tons/day.

TABLE A-34. ENVIRONMENTAL DATA FOR MODULE

Module -- Oil/Gas Well, Onshore
Unit -- 10^6 Btu (output)

Environmental Parameters	Fuel Input, Crude Oil
Air	
NO_x, lb	8×10^{-6} (1)
SO_2, lb	6×10^{-5} (2)
CO, lb	3×10^{-8} (3)
Particulate, lb	3×10^{-6} (4)
Total organic material, lb	4×10^{-7} (5)
Heat, 10^6 Btu	0
Water	
Suspended solids, lb	0
Dissolved solids, lb	6.2 (6)
Total organic material, lb	0.008 (7)
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	
Occupational Health	
Deaths	2.2×10^{-9} (8)
Total Injuries	2.1×10^{-7} (9)
Man Days Lost	3.5×10^{-5} (10)
Land Use, acre-hr/10^6 Btu	0.06 (11)
Approx. Module Efficiency	100%

Footnotes for Table A-34:

(1) a. Amount of oil that becomes air pollutants per barrel of oil produced (assumed) = 2 x 10^{-5} barrels.
b. Heating value of oil (assumed) = 6.3 x 10^6 Btu/bbl.
c. NO_x emission factor(A-1) = 60 lb/10^3 gal.
d. Oil is assumed to be the same as industrial residual oil.

(2) a. SO_2 emission factor(A-1) = 157S lb/10^3 gal.
b. Sulfur content of oil, S (assumed) = 2.88%.

(3) a. CO emission factor(A-1) = 0.2 lb/10^3 gal.

(4) a. Particulate emission factor(A-1) = 23 lb/10^3 gal.

(5) a. Hydrocarbon emission factor(A-1) = 3 lb/10^3 gal.

(6) a. Dissolved solid emission comes from saltwater brine.
b. Total brine production(A-16) = 25 million bbls/day.
c. Total on shore oil production rate(A-17) = 3.3 x 10^9 bbls/year.
d. 4% of brine goes to streams (assumed).
e. There are 100 lb of dissolved solids per barrel of oil (assumed).

(7) a. The brine is cleaned to remove all but 50 ppm oil (assumed).

(8) a. Total number of fatal injury in oil and gas production in 1969(A-17, A-19) = 95.
b. Total energy from oil and gas production(A-17,A-18) = 43 x 10^{15}Btu.

(9) a. Total number of nonfatal injury in oil and gas production in 1969(A-17,A-19) = 9022.

(10) a. Total man-days lost(A-17,A-19) = 1.49 x 10^6 man-days.

(11) a. Land requirement for an oil well producing 6200 barrels of oil per year (assumed) = 1/4 acres.

(12) a. Efficiency of operation (assumed) = 100%.

TABLE A-35. ENVIRONMENTAL DATA FOR MODULE

Module -- Oil/Gas Well-Offshore
Unit -- 10^6 Btu (output)

Environmental Parameters	Fuel Input, Crude Oil
Air	
NO_x, lb	8×10^{-6} (1)
SO_2, lb	6×10^{-5} (2)
CO, lb	3×10^{-8} (3)
Particulate, lb	3×10^{-6} (4)
Total organic material, lb	4×10^{-7} (5)
Heat, 10^6 Btu	0
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0.002 (6)
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	2.2×10^{-9} (7)
Total Injuries	2.1×10^{-7} (8)
Man Days Lost	3.5×10^{-5} (9)
Land Use, acre-hr/10^6 Btu	0.06 (10)
Approx. Module Efficiency	100%

Footnotes for Table A-35:

(1) a. Amount of oil that becomes air pollutants per barrel of oil produced (assumed) = 2 x 10^{-5} barrels.
b. Oil is assumed to be the same as industrial residual oil.
c. Heating value of oil (assumed) = 6.3 x 10^6 Btu/bbl.
d. NO_x emission factor$^{(A-1)}$ = 60 lb/10^3 gal of oil.

(2) a. Sulfur content of oil, S (assumed) = 2.88%.
b. SO_2 emission factor$^{(A-1)}$ = 157 S lb/10^3 gal burned.

(3) a. CO emission factor $^{(A-1)}$ = 0.2 lb/10^3 gal burned.

(4) a. Particulate emission factor$^{(A-1)}$ = 23 lb/10^3 burned.

(5) a. Hydrocarbon emission factor$^{(A-1)}$ = 3 lb/10^3 burned.

(6) a. Amount of oil discharged to water per barrel of oil produced (assumed) = 4 x 10^{-5} barrels.
b. Density of crude oil (assumed) = 7.3 lb/gal.

(7) a. Total number of fatal injury in oil and gas production in 1969$^{(A-17,A-19)}$ = 95.
b. Total energy from oil and gas production$^{(A-17,A-18)}$ = 43 x 10^{15} Btu.

(8) a. Total number of nonfatal injury in oil and gas production in 1969$^{(A-17,A-19)}$ = 9023.

(9) a. Total man-days lost in oil and gas production in 1969$^{(A-17,A-19)}$ = 1.49 x 10^6 man-days.

(10) a. Land requirement for an oil well producing 6200 barrels of oil per year (assumed) = 1/4 acres.

(11) a. Efficiency of operation (assumed) = 100%.

TABLE A-36. ENVIRONMENTAL DATA FOR MODULE

Module -- Oil Tanker
Unit -- 10^6 Btu (Output)

Environmental Parameters	Fuel Input, Crude Oil
Air	
NO_x, lb	0.0015(1)
SO_2, lb	0.0016(2)
CO, lb	0.0013(3)
Particulate, lb	0.0021(4)
Total organic material, lb	9×10^{-5}(5)
Heat, 10^6 Btu	0.005(6)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0.015(7)
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	9×10^{-10}(8)
Total Injuries	8×10^{-8}(9)
Man Days Lost	1.5×10^{-5}(10)
Land Use, acre-hr/10^6 Btu	0(11)
Approx. Module Efficiency	99.5(12)

Footnotes for Table A-36:

(1) a. NO_x emission by oil tanker to transport crude oil for a 1000 MW Power Plant(A-12) = 51 tons/year.

(2) a. SO_2 emission by oil tanker to transport crude oil for a 1000 MW Power Plant (A-12) = 55 tons/year.

(3) a. CO emission by oil tanker to transport crude oil for a 1000 MW Power Plant(A-12) = 44 tons/year.

(4) a. Particulate emission by oil tanker to transport crude oil for a 1000 MW Power Plant(A-12) = 72 tons/year.

(5) a. Hydrocarbon emission by oil tanker to transport crude oil for a 1000 MW Power Plant(A-12) = 3 tons/year.

(6) a. Efficiency of oil tanker operation (assumed) = 99.5%.

(7) a. Total oil discharge in oil transport and in tank cleaning operations(A-12) = 0.027% of shipment.

(8) a. Death rate in oil transportation by tanker(A-12) = 0.08 deaths/10^6 man-hours.
b. Man-hours required to transport the amount of crude oil to
(9) operate a 1000 MW Power Plant(A-12) = 7×10^5 man-hours.

a. Injury rate in oil transportation by tanker(A-12) = 7.22 injuries/10^6 man-hours.

(10) a. Man-days lost per death (assumed) = 6000 days/death.
b. Man-days lost per injury (assumed) =125 days/injury.

(11) a. Land requirement for port facilities not estimated.

(12) a. Efficiency of oil tanker (assumed) = 99.5%.

TABLE A-37. ENVIRONMENTAL DATA FOR MODULE

Module -- Oil Pipeline
Unit -- 10^6 Btu (output)

Environmental Parameters	Fuel Input, Crude Oil
Air	
NO_x, lb	0.009(1)
SO_2, lb	0.016(2)
CO, lb	2×10^{-5}(3)
Particulate, lb	0.002(4)
Total organic material, lb	0.0003(5)
Heat, 10^6 Btu	0.009(6)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	9×10^{-10}(7)
Total Injuries	8×10^{-8}(8)
Man Days Lost	1.5×10^{-5}(9)
Land Use, acre-hr/10^6 Btu	0.3(10)
Approx. Module Efficiency	99.1(11)

Footnotes for Table A-37:

(1) a. Fraction of crude oil transported by pipeline(A-20) = 77.4%.
b. Total crude oil transported in 1970(A-20) = 1.58×10^9 barrels.
c. Fraction of crude oil transported by diesel powered pump(A-21) = 16.3% of crude oil transported by pipeline.
d. Crude oil consumed to supply power for pumping(A-22) = 1.45×10^8 gal/year.
e. NO_x emission factor(A-1) = 80 lb/10^3 gal burned.
f. Heating value of crude oil (assumed) = 6.3×10^6 Btu/bbl.

(2) a. SO_2 emission factor(A-1) = 142 lb/10^3 gal burned.

(3) a. CO emission factor(A-1) = 0.2 lb/10^3 gal burned.

(4) a. Particulate emission factor(A-1) = 16 lb/10^3 gal burned.

(5) a. Hydrocarbon emission factor(A-1) = 3 lb/10^3 gal burned.

(6) a. Assumed efficiency of oil pipeline = 99.1%.

(7) a. Death rate in oil transportation by pipeline (assumed) = 0.08 deaths/10^6 man-hours.
b. Man-hours required to transport the amount of oil for running a 1000 MW Power Plant (assumed) = 7×10^5 man-hours.

(8) a. Injury rate in oil transportation by pipeline (assumed) = 7.22 injuries/10^6 man-hours.

(9) a. Man-days lost per death (assumed) = 6000 days/death.
b. Man-days lost per injury (assumed) = 125 days/injury.

(10) a. Land usage for pipeline(A-12) = 65 acres/year.
b. Period of land use (assumed) = 35 years.

(11) a. Efficiency of pipeline operation (assumed) = 99.1%.

TABLE A-38. ENVIRONMENTAL DATA FOR MODULE

Module -- Oil Barge
Unit -- 10^6 Btu (Output)

Environmental Parameters	Fuel Input, Residual Oil
Air	
NO_x, lb	0.0013(1)
SO_2, lb	0.0014(2)
CO, lb	0.0011(3)
Particulate, lb	0.0018(4)
Total organic material, lb	0.0008(5)
Heat, 10^6 Btu	0.004(6)
Water	
Suspended solids, lb	nil
Dissolved solids, lb	nil
Total organic material, lb	0.015(7)
Heat, 10^6 Btu	nil
Acid (H_2SO_4), lb	nil
Solid	
Slag, lb	nil
Ash, lb	nil
Sludge, lb	nil
Tailings, lb	nil
Hazardous, lb	nil
By-Products	nil
Occupational Health	
Deaths	9×10^{-10}(8)
Total Injuries	8×10^{-8}(9)
Man Days Lost	1.5×10^{-5}(10)
Land Use, acre-hr/10^6 Btu	0(11)
Approx. Module Efficiency	99.6%(12)

Footnotes for Table A-38:

(1) a. Assume 20,000 tons per shipment.
b. NO_x emission factor for motor ship$^{(A-1)}$ = 1.4 lb/mi.
c. Trip distance per shipment (assumed) = 325 miles.

(2) a. SO_2 emission factor for motor ship$^{(A-1)}$ = 1.5 lb/mi for 0.5% sulfur content for fuel.

(3) a. CO emission factor for motor ship$^{(A-1)}$ = 1.2 lb/mi.

(4) a. Particulate emission factor for motor ship$^{(A-1)}$ = 2lb/mi.

(5) a. Hydrocarbon emission factor for motor ship$^{(A-1)}$ = 0.9 lb/mi.

(6) a. Total heat required per 10^6 Btu transported (assumed) = 3800 Btu.

(7) a. Total oil discharge in oil transport and in tank cleaning operations$^{(A-12)}$ = 0.27% of shipment.

(8) a. Death rate in oil transportation by barge$^{(A-12)}$ (assume that barge operation is similar to tanker operation) = 0.08 deaths/10^6 man-hours.
b. Man-hour required to transport the amount of crude oil to operate a 1000 MW Power Plant$^{(A-12)}$ = 7 x 10^5 man-hours.

(9) a. Injury rate in oil transportation by barge$^{(A-12)}$ (assume that barge operation is similar to tanker operation) = 7.22 injuries/10^6 man-hours.

(10) a. Man-days lost per death (assumed) = 6000 days/death.
b. Man-days lost per injury (assumed) = 125 days/injury.

(11) a. Land requirement for port facilities not estimated.

(12) a. Energy consumption rate per 10^6 Btu of crude oil transported (assumed) = 3800 Btu.

TABLE A-39. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Refinery, Domestic Crude
Unit - 10^6 Btu (output)

Environmental Parameters	Fuel Input, Domestic Crude(0.76% S)(1)
Air	
NO_x, lb	0.023(2)
SO_2, lb	0.12(3)
CO, lb	0.003(4)
Particulate, lb	0.002(5)
Total organic material, lb	0.025(6)
Heat, 10^6 Btu	0.10(7)
Water	
Suspended solids, lb	0.004(8)
Dissolved solids, lb	0.09(9)
Total organic material, lb	0.001(10)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0.0004(11)
Solid	
Slag, lb	0
Ash, lb	0
Sludge (dry weight), lb	0.007(12)
Tailings, lb	0
Hazardous, lb	0
By-Products, lb	0.24(13)
Occupational Health	
Deaths	1.3×10^{-9}(14)
Total Injuries	9.6×10^{-8}(15)
Man Days Lost	2.3×10^{-5}(16)
Land Use, acre-hr/10^6 Btu	0.008(17)
Approx. Module Efficiency	90%(18)

Footnotes for Table A-39:

(1) a. Sulfur content of input crude taken as 0.76%.

(2) a. Average (see Appendix L) refinery energy consumption(A-24) = 70,400 Btu/bbl crude oil processed.
b. Assume all energy supplied by combustion of crude or refinery products.
c. Heating value of crude oil (assumed) = 6.3 x 10^6 Btu/bbl.
d. NO_x emission from combustion operations (see Appendix L) = 130 lb/10^3 bbl crude oil processed.

(3) a. Assume 0.75% S residual burned as refinery fuel.
b. SO_2 emission (Table L-3) = 695 lb/10^3 bbl crude oil processed.
c. 95% removal, no Claus plant tail gas treatment.

(4) a. CO emission from catalytic cracking catalyst regenerator (see Appendix L) = 15 lb/10^3 bbl crude oil processed.

(5) a. Particulate emission from catalytic cracking (see Appendix L) = 12 lb/10^3 bbl crude oil processed (after controlled by cyclones).

(6) a. Hydrocarbon emission (see Appendix L) = 140 lb/10^3 bbl crude oil processed.

(7) a. Refinery energy consumption(A-24) = 704,000 Btu/bbl of crude oil processed.
b. Heating value of crude oil (assumed) = 6.3 x 10^6 Btu/bbl.

(8) a. Suspended solids emission (assumed) = 20 lb/10^3 bbl processed.

(9) a. Dissolved solids emission (assumed) = 500 lb/10^3 bbl processed.

(10) a. Total organic material emission (assumed) = 8 lb/10^3 bbl processed.

(11) a. Phenol emission (assumed) = 2 lb/10^3 bbl processed.

(12) a. Average sludge production rate(A-25) = 0.08 $yd^3/10^3$ bbl processed.
b. Density of sludge (assumed) = 60 lb/ft^3.
c. Solid content of sludge (assumed) = 30%.

(13) a. Assume an average of 0.2% sulfur in the products (see Appendix L).
b. Density of crude oil (assumed) = 7.29 lb/gal.

(14) a. Deaths attributed to the operation of a refinery supplying fuel to a 1000 MW power plant(A-12) = 0.09 deaths.

(15) a. Injuries attributed to the operation of a refinery supplying fuel to a 1000 MW power plant(A-12) = 6.4 injuries.

(16) a. Total work days lost attributed to the operation of a refinery supplying fuel to a 1000 MW power plant(A-12) = 1530 man-days.

(17) a. Minimum land requirement for refinery processing units (assumed) = 2 acres/1000 bbl/day.

(18) a. Energy required to operate plant(A-24) = 704,000 Btu/bbl crude oil processed.

TABLE A-40. ENVIRONMENTAL DATA FOR MODULE

Module - Conventional Refinery, Imported Crude
Unit - 10^6 Btu

Environmental Parameters	Fuel Input, Arabian Crude (1.63% S)(1)	Fuel Input, Kuwait Crude (2.5% S)(2)
Air		
NO_x, lb	0.023(3)	0.023
SO_2, lb	0.12(4)	0.15(5)
CO, lb	0.003(6)	0.003
Particulate, lb	0.002(7)	0.002
Total organic material, lb	0.025(8)	0.025
Heat, 10^6 Btu	0.1(9)	0.1
Water		
Suspended solids, lb	0.004(10)	0.004
Dissolved solids, lb	0.09(11)	0.09
Total organic material, lb	0.001(12)	0.001
Heat, 10^6 Btu	Negligible after cooling tower	
Acid (H_2SO_4), lb	0.0004(13)	0.0004
Solid		
Slag, lb	0	0
Ash, lb	0	0
Sludge (dry weight), lb	0.007(14)	0.007
Tailings, lb	0	0
Hazardous, lb	0	0
By-Products, lb	0.71(15)	1.17(15)
Occupational Health		
Deaths	1.3×10^{-9}(16)	1.3×10^{-9}
Total Injuries	9.6×10^{-8}(17)	9.6×10^{-8}
Man Days Lost	2.3×10^{-5}(18)	2.3×10^{-5}
Land Use, acre-hr/10^6 Btu	0.008(19)	0.008
Approx. Module Efficiency	90%(20)	90%

Footnotes for Table A-40:

(1) a. Sulfur content of Arabian crude (assumed) = 1.63%.

(2) a. Sulfur content of Kuwait crude (assumed) = 2.5%.

(3) a. Refinery energy consumption (assume 0.75% resid)(A-24) = 704,000 Btu/bbl crude oil processed.
b. NO_x emission from combustion operations (see Appendix L) = 130 lb/10^3 bbl crude oil processed.
c. Heating value of crude oil (assumed) = 6.3×10^6 Btu/bbl.

(4) a. SO_2 emission (see Figure L-3, Appendix L) = 742 lb/10^3 bbl crude oil processed.
b. 99% removal with Claus plant tail-gas treatment.

(5) a. SO_2 emission (see Table L-3) = 950 lb/10^3 bbl crude oil processed.
b. 99% removal with Claus plant tail-gas treatment.

(6) a. CO emission from catalytic cracking catalyst regenerator (assumed) = 15 lb/10^3 bbl crude oil processed.

(7) a. Particulate emission from catalytic cracking (assumed) = 12 lb/10^3 bbl crude oil processed.

(8) a. Hydrocarbon emission (assumed) = 140 lb/10^3 bbl crude oil processed.

(9) a. Heat consumption rate(A-24) = 704,000 Btu/bbl crude oil processed.
b. Heating value of crude oil assumed to be 6.3×10^6 Btu/bbl.

(10) a. Suspended solid emission (assumed) = 20 lb/10^3 bbl crude oil processed.

(11) a. Dissolved solids emission (assumed) = 500 lb/10^3 bbl crude oil processed.

(12) a. Total organic material emission (assumed) = 8 lb/10^3 bbl processed.

(13) a. Phenol emission (assumed) = 2 lb/10^3 bbl processed.

(14) a. Average sludge production rate(A-25) = 0.08 $yd^3/10^3$ bbl processed.
b. Density of sludge (assumed) = 60 lb/ft^3.
c. Solid content of sludge (assumed) = 30%.

(15) a. Assume an average 0.2% sulfur in the products (see Appendix L).
b. Density of crude oil (assumed) = 7.3 lb/gal.

(16) a. Deaths attributed to the operation of a refinery supplying fuel to a 1000 MW power plant(A-12) = 0.09 deaths.

(17) a. Injuries attributed to the operation of a refinery supplying fuel to a 1000 MW power plant(A-12) = 6.4 injuries.

(18) a. Total man-days lost attributed to the operation of a refinery supplying fuel to a 1000 MW power plant(A-12) = 1530 man-days.

(19) a. Minimum land requirement for refinery processing units (assumed) = 2 acres/1000 bbl/day.

(20) a. Heat loss for operation of a plant(A-24) = 704,000 Btu/bbl crude oil processed.

TABLE A-41. ENVIRONMENTAL DATA FOR MODULE

Module - Topping Refinery, Kuwait Crude
Unit - 10^6 Btu

Environmental Parameters	Fuel Input, Kuwait Crude (2.5% S)(1)
Air	
NO_x, lb	0.031(2)
SO_2, lb	0.071(3)
CO, lb	Nil
Particulate, lb	0.009(4)
Total organic material, lb	0.013(5)
Heat, 10^6 Btu	0.08(6)
Water	
Suspended solids, lb	0.004(7)
Dissolved solids, lb	0.09(8)
Total organic material, lb	0.001(9)
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0.00014(10)
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0.007(11)
Tailings, lb	0
Hazardous, lb	0
By-Products	1.21(12)
Occupational Health	
Deaths	1.3×10^{-9}(13)
Total Injuries	9.6×10^{-8}(14)
Man Days Lost	2.3×10^{-5}(15)
Land Use, acre-hr/10^6 Btu	0.008(16)
Approx. Module Efficiency	92%(17)

Footnotes for Table A-41:

(1) a. Sulfur content of Kuwait crude (assumed) = 2.5%

(2) a. Refinery energy consumption (assume 0.75% S resid) = 500,000 Btu/bbl crude oil processed).
b. NO_x emission from combustion operations (see Appendix L) = 170 lb/10^3 bbl crude oil processed.
c. Heating value of crude oil (assumed) = 6.3 x 10^6 Btu/bbl.

(3) a. SO_2 emission from combustion (see Appendix L) = 380 lb/10^3 bbl crude oil processed.
b. Assume 70% of sulfur in input crude is converted to H_2S during processing. Assume Claus plant tail-gas treatment to 9918% removal. Residual SO_2 emission = 25 lb/1000 bbl crude.

(4) a. Particulate emission from catalytic cracking catalysis regeneration (see Appendix L) = 49 lb/10^3 bbl crude oil processed.

(5) a. Hydrocarbon emission (see Appendix L) = 84 lb/10^3 bbl processed.

(6) a. Heat consumption rate, assumed 70% of conventional refinery) = 500,000 Btu/bbl crude oil processed.
b. Heating value of crude oil (assumed) = 6.3 x 10^6 Btu/bbl

(7) a. Suspended solids emission (assumed) = 20 lb/10^3 bbl processed.

(8) a. Dissolved solids emission (assumed) = 500 lb/10^3 bbl processed.

(9) a. Total organic material emission (assumed) = 8 lb/10^3 bbl processed.

(10) a. Phenols emission (assumed) = 0.8 lb/10^3 bbl processed.

(11) a. Average sludge production rate(A-25) - 0.08 $yd^3/10^3$ bbl processed.
b. Density of sludge (assumed) = 60 lb/ft^3.
c. Solid content of sludge (assumed) = 30%.

(12) a. Assume an average of 0.2% S in the products (see Appendix L).
b. Density of crude oil (assumed) = 7.3 lb/gal.

(13) a. Deaths attributed to the operation of a refinery supplying fuel to a 1000 MW power plant(A-12) = 0.09 deaths.

(14) a. Injuries attributed to the operation of a refinery supplying fuel to a 1000 MW power plant(A-12) = 6.4 injuries.

(15) a. Total man-days lost attributed to the operation of a refinery supplying fuel to a 1000 MW power plant(A-12) = 1530 man-days.

(16) a. Minimum land requirement for refinery processing units (assumed) = 2 acres/10^3 bbl/day.

(17) a. Energy requirement for operation of a plant assumed to be 70% of conventional refinery = 500,000 Btu/bbl processed.

TABLE A-42. ENVIRONMENTAL DATA FOR MODULE

Module -- Conventional Boiler
Unit -- 10^6 Btu (input)

Environmental Parameters	Fuel Input, Resid from Domestic Crude (S = 1.75%)(1)
Air	
NO_x, lb	0.70(2)
SO_2, lb	1.83(3)
CO, lb	0
Particulate, lb	0.05(4)
Total organic material, lb	0.01(5)
Heat, 10^6 Btu	0.63(8)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	
Occupational Health	
Deaths	1.5×10^{-10}(7)
Total Injuries	8.9×10^{-9}(8)
Man Days Lost	2.9×10^{-6}(9)
Land Use, acre-hr/10^6 Btu	0.04(10)
Approx. Module Efficiency	37%(11)

Footnotes for Table A-42:

(1) a. Sulfur content of resid from domestic crude, S, is assumed to be 1.75%.

(2) a. NO_x emission factor$^{(A-1)}$ = 105 lb/10^3 gal.
b. Heating value of resid (assumed) = 6.3 x 10^6 Btu/bbl.

(3) a. SO_2 emission factor$^{(A-1)}$ = 157 S lb/10^3 gal.

(4) a. Particulate emission factor$^{(A-1)}$ = 8 lb/10^3 gal.

(5) a. Hydrocarbon emission factor$^{(A-1)}$ = 2 lb/10^3 gal.

(6) a. Efficiency of oil fired Power Plant (assumed) = 37%.

(7) a. Deaths attributed to a 1000 MW Power Plant$^{(A-12)}$ = 0.01 death.

(8) a. Injuries attributed to a 1000 MW Power Plant$^{(A-12)}$ = 0.6 injuries.

(9) a. Man-days lost per death (assumed) = 6000 days/injury.
b. Man-days lost per injury (assumed) = 230 days/injury.

(10) a. Land requirement for a 1000 MW oil fired Power Plant$^{(A-12)}$ = 300 acres.

(11) a. Efficiency of oil fired Power Plant (assumed) = 37%.

TABLE A-43. ENVIRONMENTAL DATA FOR MODULE

Module -- Conventional Boiler
Unit -- 10^6 Btu (input)

Environmental Parameters	Fuel Input, Resid from Topping Refinery
	(S = 0.70%)(1)
Air	
NO_x, lb	0.70(2)
SO_2, lb	0.73(3)
CO, lb	0
Particulate, lb	0.05(4)
Total organic material, lb	0.01(5)
Heat, 10^6 Btu	0.63(6)
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	1.5×10^{-10}(7)
Total Injuries	8.9×10^{-9}(8)
Man Days Lost	2.9×10^{-6}(9)
Land Use, acre-hr/10^6 Btu	0.04(10)
Approx. Module Efficiency	37%(11)

Footnotes for Table A-43:

(1) a. Sulfur content of resid from topping refinery, S, is assumed as 0.7%.

(2) a. NO_x emission factor(A-1) = 105 lb/10^3 gal.
b. Heating value of resid (assumed) = 6.3 x 10^6 Btu/bbl.

(3) a. SO_2 emission factor(A-1) = 157 S lb/10^3 gal.

(4) a. Particulate emission factor(A-1) = 8 lb/10^3 gal.

(5) a. Hydrocarbon emission factor(A-1) = 2 lb/10^3 gal.

(6) a. Efficiency of oil fired Power Plant (assumed) = 37%.

(7) a. Death attributed to a 1000 MW Power Plant(A-12) = 0.01 death.

(8) a. Injuries attributed to a 1000 MW Power Plant(A-12) = 0.6 injuries.

(9) a. Man-days lost per death (assumed) = 6000 days/death.
b. Man-days lost per injury (assumed) = 230 days/injury.

(10) a. Land requirement for a 1000 MW oil fired Power Plant(A-12) = 300 acres.

(11) a. Efficiency of oil fired Power Plant (assumed) = 37%.

TABLE A- 44. ENVIRONMENTAL DATA FOR MODULE

Module - Municipal Refuse Processing (St. Louis Method)
Unit - 10^6 Btu (output)

Environmental Parameters	
Air	
NO_x, lb	0
SO_2, lb	0
CO, lb	0
Particulate, lb	ND
Total organic material, lb	ND
Heat, 10^6 Btu	ND
Water	
Suspended solids, lb	0
Dissolved solids, lb	0
Total organic material, lb	0
Heat, 10^6 Btu	0
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	0
Hazardous, lb	0
By-Products	21.4 lb steel/10^6 Btu(1)
Occupational Health	
Deaths	ND
Total Injuries	ND
Man Days Lost	ND
Land Use, acre-hr/10^6 Btu	0.034(2)
Approx. Module Efficiency	100

ND = Not determined.

Footnotes for Table A-44:

(1) Assume "as received" refuse has an average heating value of 3500 Btu/lb and contains 7.5% metal recoverable by magnetic separation.

(2) Assume 10 acres are required for a 1000 T/day refuse processing plant.

TABLE A-45. ENVIRONMENTAL DATA FOR MODULE

Module - Municipal Refuse Burning, Conv. Boiler, Limestone Scrubber
Unit - 10^6 Btu (input to boiler)

Environmental Parameters	Fuel Input Prepared Municipal Refuse(1)
Air	
NO_x, lb	0.6(2)
SO_2, lb	0.066(3)
CO, lb	ND
Particulate, lb	0.26(4)
Total organic material, lb	ND
Heat, 10^6 Btu	0.65(5)
Water	
Suspended solids, lb	Negligible
Dissolved solids, lb	Negligible
Total organic material, lb	Negligible
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	0
Solid	
Slag, lb	0
Ash, lb	26.4(6)
Sludge, lb	28.6(7)
Tailings, lb	-285(8)
Hazardous, lb	0
By-Products	0
Occupational Health	
Deaths	ND
Total Injuries	ND
Man Days Lost	ND
Land Use, acre-hr/10^6 Btu	0.1(9)
Approx. Module Efficiency	35%(9)

ND = Not determined.

Footnotes for Table A-45:

(1) Assume the as-received refuse has the following composition: 0.23% sulfur,(A-29) 18.5% ash,(A-29) 3500 Btu/lb.(A-30) Assume that 7.5% of the refuse is removed by magnetic separation. Processed refuse composition would then be: 0.25% S, 20% ash, and 3785 Btu/lb.

(2) Assume equal to value for coal-fired power plant.

(3) a. Assume 50% of input sulfur appears in flue gas(A-31)
b. Assume 90% scrubber efficiency.

(4) a. Assume 50% of ash content appears in flue gas particulate. (Lower than for coal due to presence of noncombustibles).
b. Assume 99% particulate collection efficiency.

(5) Boiler efficiency (assumed) = 35%, balance to waste heat.

(6) Assume 50% of input ash remains as bottom ash.

(7) a. Sludge from SO_2 removal plus fly ash collected.
b. Sulfur content of sludge (assumed) = 12%.
c. Fly ash collected by scrubber = .99 x 50% of input ash.

(8) Credit quantity of original refuse processed and burned rather than landfilled = 1 lb/3500 Btu x 10^6 = 285 lb/10^6 Btu.

(9) Assume equal to coal-fired power plant.

TABLE A- 46. ENVIRONMENTAL DATA FOR MODULE

Module - Space Heating(1)
Unit - 10^6 Btu Useful Energy Delivered

	Fuel Input,			
Environmental Parameters	Electricity	Natural Gas	Oil	Coal
Air				
NO_x, lb	0	0.115	0.193	0.233
SO_2, lb	0	0.001	0.376(2)	4.42(3)
CO, lb	0	0.022	0.043	6.98
Particulate, lb	0	0.007	0.024	1.55
Total organic material, lb	0	0.006	0.006	1.55
Heat, 10^6 Btu	0	0.43	0.43	1.0
Water				
Suspended solids, lb	0	0	0	0
Dissolved solids, lb	0	0	0	0
Total organic material, lb	0	0	0	0
Heat, 10^6 Btu	0	0	0	0
Acid (H_2SO_4), lb	0	0	0	0
Solid				
Slag, lb	0	0	0	ND
Ash, lb	0	0	0	ND
Sludge, lb	0	0	0	0
Tailings, lb	0	0	0	0
Hazardous, lb	0	0	0	0
By-Products				
Occupational Health	ND	ND	ND	ND
Deaths				
Total Injuries				
Man Days Lost				
Land Use, acre-hr/10^6 Btu	ND	ND	ND	ND
Approx. Module Efficiency	100%	70%	70%	50%

ND = Not determined.

Footnotes for Table A-46:

(1) Data taken from Table X-7, Appendix X, for Residential Case II. All emissions calculated per million Btu of useful energy delivered.

(2) Assume 0.3% S in oil.

(3) Assume 1.5% S in coal.

(4) Non-useful energy lost as flue gas heat.

TABLE A-47. ENVIRONMENTAL DATA FOR MODULE

Module - Nuclear Fission (overall system)
Unit - 10^6 Btu (input to power plant)

Environmental Parameters	
Air	
NO_x, lb	0.003(1)
SO_2, lb	0
CO, lb	0
Particulate, lb	--
Total organic material, lb	--
Heat, 10^6 Btu	0.68(2)
Water	
Suspended solids, lb	0.022(3)
Dissolved solids, lb	--
Total organic material, lb	--
Heat, 10^6 Btu	Negligible after cooling tower
Acid (H_2SO_4), lb	9
Solid	
Slag, lb	0
Ash, lb	0
Sludge, lb	0
Tailings, lb	4(4)
Hazardous, lb	Not estimated
By-Products	0
Occupational Health	
Deaths	1.5 x 10^{-9}(5)
Total Injuries	0.9 x 10^{-7}
Man Days Lost	1.3 x 10^{-5}
Land Use, acre-hr/10^6 Btu	0.37(6)
Approx. Module Efficiency	30% (overall)(7)

Footnotes for Table A-47:

(1) a. Equivalent pounds of NO_x, see Appendix B, for derivation of conversion factor of 0.7 lb/curie.
b. Table V-1, Appendix V, gives total annual radiological emissions to air from the production of 50 gigawatt-years of energy as 1.94×10^7 curies/year. The efficiency of the reaction is about 32%. Hence, $(1.94 \times 10^7)/(50 \times 10^6 \times 3413/0.32 \times 8760) = 4.15 \times 10^{-9}$ Ci/Btu, or 4.15×10^{-3} Ci/10^6 Btu. This value times the conversion factor, 0.7 lb/Ci = 3×10^{-3} equivalent pounds of $NO_x/10^6$ Btu input to the power plant.

(2) a. Thermal efficiency of the power plant is assumed to be 32%.

(3) a. Equivalent pounds of D.O., see Appendix B for derivation of conversion factor of 7 lb/curie.
b. Table V-2, Appendix V, gives total annual radiological emissions water for nuclear power production as given in Footnote 1b above as 2.7×10^5 curies/year.

(4) a. Table V-3, Appendix V, gives 1.3×10^8 cubic yards of waste rock produced annually from open pit and underground mining. All other solid wastes are small in comparison.
b. The surface mining operation is assumed to practice land reclamation. The ratio of solid waste produced by deep mining to that produced from open pit is taken as 1 to 30, and the amount of uranium mined by each method is roughly equal (see Appendix V). Hence, 4.2×10^6 cubic yards of waste can be attributed to deep mining of uranium associated with the level of power production stated in footnote 1b above.

(5) a. Occupational health estimates associated with a 1000 MW nuclear plant (8.7×10^{13} Btu input) are: fatalities = 0.135, injuries = 7.26, and man-days lost = 1125.(A-12)

(6) a. The value represents the summation of the following estimates: mining and milling 0.01, processing 0.06, transportation 0.2, and power plant 0.1.

(7) a. Milling losses are estimated at 5%. Power generation efficiency is estimated at 32%. Net overall efficiency = 30%.

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APPENDIX B

METHODOLOGY FOR RANKING OF ENERGY SYSTEMS

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APPENDIX B

METHODOLOGY FOR RANKING OF ENERGY SYSTEMS

Approach

The evaluation of alternative systems for the production of useful energy and the modules contained within these systems required the comparison of a variety of environmental burdens. These burdens can arise through different steps in the process, and various components of the environment can be affected. Some system of ranking which attempts to collect these complex burdens into a single number or set of numbers is desirable as part of the evaluation scheme. An attempt has been made during this phase of the study to develop a method for the initial ranking of energy systems.

In concept, the ranking system used is based upon methodology developed for the Bureau of Reclamation, U.S. Department of the Interior.(B-1) This concept involves a hierarchy of environmental burdens under four major environmental categories. Each of these categories is divided into environmental components, which in turn can be separated into environmental parameters. An environmental parameter is a single measurement or a series of measurements of the burden. If the environmental burden for the system or activity under consideration is to be derived properly, it is necessary to combine the environmental burdens at each level of this hierarchy. Weighting factors are assigned as a measure of the importance of a burden at any particular level of the hierarchy and can be used to accommodate the different units used in the measurement of the various burdens.

Due to the limited time for the present study, a complete hierarchy of environmental burdens was not developed. An attempt has been made to develop a quantitative system utilizing five environmental components. The components assumed to be of significance to the evaluation of energy systems are

Air
Water
Solid Waste
Land Use
Radiation

Various parameters within each component were quantified as appropriate to each module. The goal of the ranking procedure used was to derive a single environmental index for the energy system under consideration.

This index is represented as follows:

$$I_i = \Sigma_m W_{m_i} \Sigma_n W_n \Sigma_p W_p Q_p,$$

I_i = Environmental index for energy system i
W_{m_i} = Weight of module m in system i
W_n = Weight of environmental component n
W_p = Weight of parameter p
Q_p = Quantity of p produced per unit of energy.

A computer code was written to facilitate the calculation of the environmental indices for the relatively large numbers of modules and for the combination of these modules into systems. The computer code also permitted the performance of sensitivity calculations to gain an appreciation of the dependence of the environmental index on uncertainties in input data. The assignment of weighting factors, the development of the computer code, and the sensitivity calculations are discussed in the following sections.

Derivation of Weighting Factors

Weighting Factors for Air Parameters

The air pollution index is based on the primary emission standards and pollutant levels in terms of emissions in pounds per million Btu. The following primary standard values were employed.

SO_x	$80\ \mu g/m^3$	annual average value
NO_x	$100\ \mu g/m^3$	
Particulate	$75\ \mu g/m^3$	
CO	$1000\ \mu g/m^3$	annual average value extrapolation from $10{,}000\ mg/m^3/8$ hr
Hydrocarbons	$160\ \mu g/m^3$	1 hr - used as annual average value
Trace metals		
Be	$0.1\ \mu g/m^3$	
Hg	$1.0\ \mu g/m^3$	
Pb	$2.0\ \mu g/m^3$	

Fine particles ($< 1\mu$) and thermal emissions also should be included in the consideration of air emissions. Standard values which could be used in the same manner as the values above were not identified for these pollutants in this study, so these emissions were not included in the calculations of the environmental index. Their omission from the current assessment is not meant to minimize their importance, however.

The above values were referenced to the NO_x value. The resulting weighting factors are:

Pollutant	Factor (W_p)	Babcock's Factors (normalized)
NO_x	1 (reference)	514/514 - 1.00
SO_x	$\frac{100}{80} = 1.25$	514/1430 = 0.36
TSP	$\frac{100}{75} = 1.33$	514/375 = 1.37
CO	$\frac{100}{1000} = 0.10$	514/40,000 = 0.01
HC	$\frac{100}{160} = 0.63$	514/19,300 = 0.03
Trace metals		
Be	10^4	
Hg	10^2	
Pb	50	

Thus, the assumption is made that an increase of 1 $\mu g/m^3$ of SO_x is as detrimental as 1.25 $\mu g/m^3$ of NO_x and an increase of 1 $\mu g/m^3$ of CO is as undesirable as 0.1 mg/m^3 of NO_x, etc.

A similar type of normalizing approach for the development of a combined index for the measurement of air pollution has been suggested by Babcock.(B-2) His factors which were based upon California air quality standard are shown for comparison and have been normalized to NO_x.

Weighting Factors for Water Parameters

The procedure used to derive the weighting factors for the parameters within the water component is based upon the same concept as that used for the air factors, i.e., based upon water quality standards. Credence to this approach is given in the work of Brown(B-3) and Horton(B-4). In addition to these references, Wolman(B-5) has also identified important indicators of water quality. The water quality parameters used in the present study are:

Parameter	Water Quality	Weighting Factor (W_p)
DO (Dissolved Oxygen)	5.0 ppm	1.00
BOD (Biological Oxygen Demand)	5.0 ppm	1.00
Total dissolved solids	500 ppm	0.01
Oil	15 ppm	0.33
Phenol	0.3 ppm	17
Trace metals		
Cu	0.2 ppm	25
Zn	0.3 ppm	17
Cd	0.3 ppm	17
Hg	0.5 ppm	10^4
Pb	0.1 ppm	50

The weighting factors were derived by normalizing to the value of dissolved oxygen.

Weighting Factors for Solid Waste

Many modules produce some solid waste. Consideration of the quantity of this waste also can be assessed as part of the environmental impact. The weighting factors were assigned on the basis of a gross scale of importance based on the composition of the solid waste.

Importance	Weighting Factor
Stable solid, leaching not important	1
Environmental pollution potential if leached or eroded	2
Hazardous if leached or eroded	3
Directly hazardous (contact, proximity, etc.)	4

Land Use Parameters

The land use parameter includes the land area involved and a time factor. For the processing and utilization modules the proper unit arises from the fact that a certain land area is associated with a plant with a stated throughput, say tons of coal per hour or the equivalent heating value (Btu per hour). When the area in acres is divided by this energy rate the resulting units are acre-hour/10^6 Btu. For the extraction modules the area is associated with a total energy (e.g., tons of coal per acre). The resulting value in acres/10^6 Btu is converted to consistent units by multiplying the value by the length of time assumed for the operation.

Different weighting factors could be applied to reflect geographical location, compatibility with surroundings, dedicated or temporary use, and other related factors. However, weighting factors for land use have been taken as unity for all calculations performed to date.

Weighting Factors for Radioactivity

A rigorous comparison of the environmental effects of material emissions and radioactive emissions from energy generation is beyond the scope of this present study. One of the major difficulties is the need to consider both somatic and genetic effects for radioactivity against only somatic effects of material emissions. While lethal levels of radioactive and nonradioactive pollutants are reasonably well known, the exposures to the public encountered in energy generation are well below these lethal values. Dose-effects relationships down to the near background or natural concentrations are not known with certainty for either type of pollutant and the comparability between the assumed relationships of both types of pollutants is strictly hypothetical.

Nevertheless, in this attempt to compare the environmental burden of a number of energy systems, it was desirable to develop some appreciation of magnitudes of the relative effects and to apply an internally consistent set of weighting factors to the emissions. Several approaches to derive a factor which would permit a comparison of nuclear and fossil fuel systems based upon effects were examined, and a method to include radioactive emissions under the air and water components was derived.

Health Costs Data. According to the Council on Environmental Quality,(B-6) the total annual health costs due to air pollution is \$6 billion. For a population of 200 million, the cost is \$30 per person per year.

Not all air pollution, however, is attributable to stationary sources. A simple estimate of the fraction of air pollution from stationary sources can be derived on a weight basis. The total air emissions in 1970 are:(B-7)

Emissions, Millions of Tons Per Year

	As Reported Fuel Combustion in Stationary Sources*	Total	Normalized to NO_x Fuel Combustion in Stationary Sources(a)	Total
CO	0.8	147.2	0.08	14.7
Particles	6.8	25.4	8.9	33.8
SO_x	26.5	33.9	33.1	42.4
HC	0.6	34.7	0.4	21.8
NO_x	10.0	22.7	10.0	22.7
	44.7	263.9	52.48	135.4

(a) Although stationary sources include more than the energy generation systems under consideration, there is little to be gained in this order-of-magnitude estimate of weighting factors to further subdivide the emissions.

The weight fraction due to stationary sources is (44.7)/(263.9) = 0.17 if the as reported data are used, and is (52.5)/(135.4) = 0.39 if the data are normalized to the NO_x values.

By applying the weight fraction data to the health costs, the annual costs are \$5 to \$12 per person due to energy generation (stationary sources). The electric utilities used 13,750 x 10^{12} Btu of fossil fuel in 1970.(B-8) Annual health costs per person for the burning of fossil fuels to produce electricity are between \$0.36 to \$0.87 x 10^{-9} per 10^6 Btu.

Sagan(B-9) has analyzed the risk to the U.S. population from all steps of the nuclear fuel cycle-occupational exposures in uranium mining and milling, manufacturing, reactor operation, and fuel reprocessing, and exposure to the public near an operating reactor. His cost data are based upon the assumption that 1 rem produces 100 cases of cancer per million persons exposed and that the cost per human life is $300,000. This places the risk-cost per rem per person at $30. The annual cost from all activities is $0.011 per person.

For 10,030 megawatts of nuclear power produced by plants now operating in the United States, the human costs for the entire U.S. population of generating that electric power are derived to be about 0.026 mill per kilowatt hour. This is equal to $1.1 x 10^{-11} per 10^6 Btu per person.

If health **and** human economic costs are used as the basis of comparison of emissions from nuclear systems and fossil systems, then emissions from the fossil fuel systems are about 100 to 300 times greater in importance than emissions from nuclear systems.

Lethality Data. For accidental or occupational exposures to NO_2, death within 3 to 5 weeks following exposure from broncheolites fibrosis obliterons results from concentrations in the range of 282 to 376 mg per m^3.(B-10) The primary ambient NO_x standard is 100 microgram per m^3 on an annual basis. If a breathing rate of 20 m^3 per day is used, the annual dose from an exposure to NO_2 at the allowed maximum ambient level is 730 mg/yr. If a mid-range lethal exposure value of 327 mg per m^3 is selected, then the ratio of an instantaneous lethal concentration to allowable ambient concentrations is about 0.4.

For acute exposure to radiation, a value of 300 to 600 Rads is considered lethal.(B-11) The maximum acceptable permissible dose to the general population from manmade sources is 170 mrem on an annual basis. If a mid-range lethal dose of 450 Rads is selected, then the ratio of lethal dose to allowable ambient doses is about 2600.

Thus, if the assumptions are made that the ambient or general population exposure standards are set to limit health effects, that the effects they are set to limit are equally severe, and that dose and dose-rate relationships can be extrapolated to ambient levels with the same degree of comparability, then using this lethality approach, fossil-fuel emissions are about 6500 times more important than emissions from nuclear systems. The validity of these assumptions is not known.

Comparison of Nuclear and Oil-fired Power Plants. An analysis has been performed by Starr, et al(B-12) to compare emissions from nuclear and oil-fired power plants in the Los Angeles basin. The analysis was restricted to the comparative public health aspects of oil-fired and nuclear power plants and their associated activities in a typical urban setting. Operation of these plants under conditions up to the present federal regulatory limits was estimated to cause 60 times more respiratory deaths due to fossil fuel pollution than cancer deaths due to nuclear plant effluents. In normal practice, neither plant would be expected to expose the public to these limits, primarily because the routine effluents must be reduced below regulatory levels to meet a variety of conditions, and would thus be expected to be substantially less (by a factor of 10 or more) under average circumstances.

In both cases the integrated accident risk (averaged over time and all episodic events) is about 10^{-5} of the continuous exposure, for either the nuclear plant or the oil-fired plant. For the analyzed accident with equal probability of occurrence, the oil-fired plant has a substantially worse public health impact than the nuclear. For example, the one-in-a-million-years event for the oil-fired plant would lead to approximately 700 respiratory deaths in a population center of 10 million people; while the one-in-a-million-years event for the nuclear plant would result in approximately one death in the same population.

Data from Los Angeles are not directly applicable to other regions of the country. However, the analysis by Starr is useful in establishing the relative significance of nuclear power and fossil fuel power emissions. The factor of 60 which he derived is of the same order of magnitude as the factor of 100 derived from health cost effect.

Derivation of Weighting Factor (W_p) for Radioactivity. In order to compare the emissions from nuclear power systems which are derived in units of curies to the emissions from fossil fuel systems which are derived in units of pounds, it was necessary to develop a conversion factor which both converts the units to the same basis and relates comparable effects. The previous discussion of health costs and lethality data gives an estimate of the relative importance of exposure to fossil fuel emissions and to radioactivity. It would appear that fossil fuel emissions are at least 100 times more important than nuclear emissions on an effect basis. In light of the uncertainties in the analysis, and the limited consideration of accidents in nuclear power systems, it has been assumed that emissions from fossil fuel systems and emissions from nuclear systems have equal importance. For normal operations, this will tend to overstate the importance of the environmental impact of nuclear power.

Comparison of emissions from the two types of systems would require a detailed analysis of each specific pollutant or radionuclide emitted. For the purposes of this study, several approximations were made. During reactor operations and fuel reprocessing it is assumed that the air emissions are predominantly the noble gases. MPC values (10 CFR, Part 20) for the noble gases are 3×10^{-7} μCi/ml and this value will be taken as the standard for the air emissions calculations. Several radionuclides can be present in the waste water, and MPC values (10 CFR, Part 20) in water for some typical radionuclides are: ^{3}H, 3×10^{-3} μCi/ml; ^{137}Cs, 2×10^{-5} μCi/ml; and ^{90}Sr, 3×10^{-7} μCi/ml. For purposes of the water effluent calculations, a mid-range value of 3×10^{-5} μCi/ml has been used for the "standard" MPC water value.

To reduce the radioactivity to the same units as the fossil fuel emissions, the following relationships are applied.

Air emissions.

$$\begin{pmatrix}\text{Radioactivity in}\\ NO_x\text{ equivalents}\end{pmatrix} = Q_{r,\text{air}} \times \frac{I_{NO_x}}{I_r} \times \frac{\begin{pmatrix}\text{Ambient}\\ \text{standard}\\ NO_x\end{pmatrix}}{\begin{pmatrix}\text{"Standard"}\\ \text{MPC air}\end{pmatrix}}$$

where Qr = quantity of radioactivity in curies

$\frac{I_{NO_x}}{I_r}$ = Factors which relates the importance of fossil fuel emissions to radioactivity in units of lb/Ci. For this analysis it is assumed to be 1.

Ambient standard, NO_x = 100 $\mu g/m^3$ = 0.23×10^{-6} lb/m^3

"Standard" (MPC) air = 3×10^{-7} Ci/m^3

$$\begin{pmatrix}\text{Radioactivity in}\\ NO_x\text{ equivalents}\end{pmatrix} = Qr \times 0.7,\ \text{lb.}$$

Water effluents. To derive a similar factor for water, radioactivity has been compared to trace metals. As noted earlier, the water quality standard values, based primarily on drinking water standards, are in the range of 0.1 to 0.3 ppm with the Hg-standard set at 0.5 ppb. For the purpose of comparison, a water quality value of 0.1 ppm will be used.

$$\begin{pmatrix}\text{Radioactivity}\\ \text{in trace metal}\\ \text{equivalents}\end{pmatrix} = Q_{r_1\,\text{water}} \times \frac{I_{\text{trace metals}}}{I_r} \times \frac{\begin{pmatrix}\text{Water quality}\\ \text{standard}\\ \text{trace metals}\end{pmatrix}}{\begin{pmatrix}\text{"Standard"}\\ MPC_{\text{water}}\end{pmatrix}}$$

As in the case of air, $I_{\text{trace metals}}/I_r$ is a factor which relates the importance of trace metals to radioactivity. It is assumed to be 1 lb per curie for this analysis.

Water quality standard, trace metals = 0.1 ppm = 2.2×10^{-4} lbs/m^3

"Standard" (MPC) water = 3×10^5 Ci/m^3

Radioactivity in trace metal equivalents = $Q_r \times 7$, lb

Since the water impacts are normalized in terms of dissolved oxygen, an additional factor of 50 has been applied to the preceding expression. Thus, to calculate the burden to the water from radioactivity, the radioactive effluents in curies is to be multiplied by 3.5×10^{-2} to obtain a comparable unit.

Ecology. Weighting factors for ecological impacts to energy systems have not been estimated for the current study. Concepts to be used, however, could follow the general approach outlined in the study for the Bureau of Reclamation.(B-1) The ecological impacts are not included in the current environmental index.

Human Factors. A combination of parameters is involved in the impact of energy systems directly upon man's environment. Data to derive quantitative weighting factors are often missing, and only a subjective approach is possible at this time. For this report only the occupational health and safety sections have been considered. These have been derived primarily of data from the Bureau of Labor Statistics.(B-13) Weighting factors have not been -erived and the human factor impacts are not included in the current environmental index.

Computer Program for Environmental Index Calculation

The computer program for the calculation of the environmental index for the energy systems evaluated encompasses seven steps.

1. Read in Data

The data read in consists of:

(a) Emission values for the components air, water, solid, and land for each module

(b) The weighting factor for each emission value within the component

(c) Weighting factors for the relative importance of air, water, solid, and land

(d) Weighting factors for module type, extraction, transportation, processing, and utilization

(e) The modules comprising each system.

2. Calculate Weighted Component Totals for Each Module

This calculation is performed by multiplying the emission values within each component by the appropriate weighting factor (read in 1-b). The result is four numbers per module representing the sum of impacts for each component--air, water, solid, and land.

3. Efficiency Correction

The weighted component totals for each module are divided by the product of the efficiencies of all subsequent modules in the system. This calculation is necessary since the module data are expressed on a basis of a million Btu. The output, and thus the associated emissions, of, say, an extraction module must be increased in proportion to the inefficiency of the power plant.

4. Calculate Normalizing Factors
The modules are arranged into systems (according to data read in 1-e) and the air, water, solid, and land totals are summed up. For the number of systems chosen, this procedure results in a total of four sums (air, water, solid, and land). The normalizing factor is then calculated as the ratio of the air sum to each of these sums.

5. Calculate the Module Index
For each module in a system, the four normalized numbers (air, water, solid, land) are weighted with respect to component weighting factors (read in 1-c) and summed. This calculation results in a single impact number for each module in a given system.

6. Calculate the System Index
For each system, consisting of several modules, the system index is calculated by multiplying each module impact number by the module weighting factor (read in 1-d). The sum of these results within a given system gives the system index.

7. Rank the Systems
Finally, ranking of the systems is performed by ordering by system index.

Sensitivity Analyses

The procedures used in deriving an environmental index for various energy systems incorporated a number of assumptions and in many cases estimates have been made of the quantities of pollutants emitted in the modules. A series of analyses were performed using the computer code previously described to test the sensitivity of the ranking of the systems to variations in the input and the assumptions that have been made. The results of these sensitivity analyses give an indication of the validity of the overall procedure and an appreciation of the reliability of the final ranking.

The results of three sets of calculations are shown in Table B-1 to illustrate the changes in rank ordering of systems that occurs with changes in weighting factors. The base case for comparison is the ranking systems where all components and modules were equally weighted. These rankings are compared to a case where the solid waste component was weighted at 30 percent of the other component weighting factors, i.e., burdens as a result of solid wastes are less important than burdens in air, water, and land utilization components. In the third case, all of the components were equally weighted, but the utilization module was weighted 3 times as great as the other modules.

In general, the overall rankings remained similar, the systems that rank high in the base case tend to rank high in the comparison case. Where the importance of solid waste component is diminished, the system using

Eastern coal and a limestone scrubber rank considerably higher than in the base case. The large quantities of solid waste produced in this system have relatively less influence on the ranking of this system. The imported oil system moves high in the ranking when greater weight is given to the utilization module. Its utilization module has a relatively low burden compared with other systems. The changes in the order of the systems are in the direction anticipated by the changes in weighting of components or models.

The sensitivity analyses performed to date are not sufficient to determine the significance of small differences in environmental indices. Until additional analyses are performed and the results evaluated, care must be taken in the interpretation of the ranking and the values assigned to the environmental index.

TABLE B-1. SENSITIVITY OF RANKING TO VARIATIONS IN WEIGHTING FACTORS

All Components and Modules Weighted Equally	$W_A=W_W=W_L=1.00$; $W_{Solid} = 0.3$ All Modules Weighted Equally	All Components Weighted Equally Utilization Modules Weighted 3 Times Greater than Others
LNG	LNG	LNG
Fluidized bed-oil	Fluidized bed-oil	Fluidized bed-oil
Gas	E coal-molten iron	Import oil-topping-CB
E coal-molten iron	E coal-pres fluid bed	Gas
W coal-conv boil	N gas-GP-CB	E coal-SRC-CB
E coal-pres fluid bed	W coal-CB+LSS	E coal-molten iron
E coal-MgO scrubber	E coal-CB+MgO	Off coi-pipe-ref-OT-CB
Import oil-topping-CB	E coal-PC-CB+LSS	E coal-pres fluid bed
E coal-PC-CB	W coal-CB	E coal-PC-CB+LSS
E coal-PC-CB+LSS	E coal-CB+LSS	On oil-pipe-ref-barge-CB
W coal-CB+LSS	E coal-SRC-CB	On oil-pipe-crude gas-pipe-gas CB
On oil-pipe-ref-barge-CB	E coal-PC-CB	W coal-CB
SRC-CB	Imp oil-topping-CB	E coal-PC-CB
CCC-CB	E coal-CCC-CB	E coal-MgO scrubber
On oil-oil pipe-crude gas-gas pipe-gas CB	E coal-Lurgi	CCC-CB
E coal-Lurgi	On oil-pipe-ref-barge-CB	W coal-CB=LSS
E coal-CB+LSS	On oil-pipe-crude gas-pipe-CB	E coal-CB+LSS
Off oil-oil pipe-ref-OT-CB	E coal-CB	E coal-Lurgi
E coal-CB	DMEC-PC-CB+LSS	On oil-pipe-ref-OT-CB
On oil-oil pipe-ref-OT-CB	Off oil-pipe-ref-OT-CB	DMEC-PC-CB
DMEC-PC-CB	DMEC-PC-CB	DMEC-PC-CB+LSS
DMEC-PC-CB+LSS	On oil-pipe-ref-OT-CB	E coal-CB
DMEC-CB	DMEC-CB	DMEC-CB

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APPENDIX C

ENVIRONMENTAL EMISSIONS--OIL AND GAS EXPLORATION, DRILLING, AND PRODUCTION

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APPENDIX C

ENVIRONMENTAL EMISSIONS--OIL AND GAS EXPLORATION, DRILLING, AND PRODUCTION

Summary

The major sources of air pollution in the exploration, drilling, and production of oil and gas are blowouts and well-testing. The number of blowouts during drilling on land from 1960 through 1970 has been reported to be 100 out of 273,000 wells. Only three significant blowouts have been reported during offshore operations since 1937. As a result of these infrequent events, hydrocarbons are injected directly into the atmosphere, and other combustion products of oil and gas can be emitted if a fire occurs with a blowout. Blowout prevention appears to be the most feasible means to reduce this type of environmental emission.

During well-testing, the gas or oil produced is burned, and the products of combustion are released to the environment. With adequate pollution control devices on the burning equipment, the quantities of these emissions can be small.

The emissions to the water environment occur through the discharge of oil and saltwater brines. Spills and blowouts release oil, and some additional oil is carried with the saltwater brines. Although the quantity of saltwater produced is greater than the quantity of oil, presently all but about 4 percent of the saltwater is returned to underground formations or otherwise disposed of in a satisfactory manner.

The total amount of oil discharged to the air, water, and land environments from all sources during exploration, drilling, and production is 6×10^{-3} percent of the oil produced.

Environmental impacts to land are limited since the area required for a drilling rig is small. The impact of oil and gas production on occupational safety and health are: fatalities, 2.2×10^{-9} per 10^6 Btu's; nonfatal injuries, 2.1×10^{-7} per 10^6 Btu's; and time lost, 3.5×10^{-5} man-days lost per 10^6 Btu's.

Technology

General Description of Operation

A comprehensive description of the operations performed in the exploration and production of oil and gas has recently been prepared by the

National Petroleum Council.(C-1) This document and its supporting references should be consulted for additional details on operations. The scope of operations of interest in the determination of the environmental emissions of oil and gas production include:

Offshore locations
  Exploration
    1. Geophysical surveying
    2. Bottom sampling
  Drilling
    1. Drilling rigs
    2. Blowouts
  Completion
    1. Formation evaluation and well-testing
    2. Production casing setting
    3. Perforation of the production casing
    4. Suspension and abandonment
  Production
    1. Stimulation
    2. Repair and recompletion
    3. Sand production
    4. Accidents and disasters

Onshore Locations
  Exploration
    1. Survey
    2. Core drilling
  Drilling
    1. Drilling operations
    2. Waste handling and disposal
    3. Blowouts
  Completion
    1. Formation evaluation and well-testing
    2. Production casing setting
    3. Setting the Christmas tree
    4. Perforation of the production casing
    5. Suspension and abandonment
  Production
    1. Stimulation
    2. Repair and recompletion
    3. Sand production
    4. Accidents and disasters

There is a high degree of similarity between offshore and onshore operations, and the two types are discussed together in the subsequent sections of this appendix. Since there is expected to be a greater increase in the amount of offshore operations between now and 1985, more emphasis is given in the discussion to offshore technology. Air pollution considerations are basically the same for the two types of operations, but water pollution problems from hydrocarbons are more significant in offshore operations and land pollution problems are more important in onshore operations.

Exploration(C-1)

Gathering of geophysical and geological data for petroleum operations in water-covered areas encompasses three categories of activities: geophysical sampling to map various specific earth conditions, bottom sampling to collect geological materials from the sea bottom, and core drilling to sample bedrock below the sea bottom.

The specific earth conditions commonly surveyed by geophysical methods to obtain data for the evaluation of the petroleum potential of an offshore area are magnetic field, gravity field, seismic (acoustic) sounding, and heat flow. Seawater chemistry measurements are also made to determine the presence of hydrocarbons. Instrumentation to obtain these types of data may be towed by a survey boat, lowered to the sea floor from the boat, or utilized above the boat. Seismic measurements are the only type of geophysical measurements that perturb the environment to any extent. The original acoustic source universally used was dynamite, and fish kills occasionally resulted from this technique. But the trend is now toward the use of more sophisticated energy sources such as encapsulated explosives (small charge), sparkers (electric spark gap), exploding wire, compressed air guns, carbide guns, gas (propane-oxygen) guns, and electro-mechanical and mechanical transducers which should eliminate fish kills. In 1969, 35 percent of all geophysical work was being done without explosives.(C-2)

Bottom samples are recovered from the sea floor by wire-line dredges, grab samplers, or gravity corers. These are essentially surface samples of the sea bottom and do not penetrate bedrock. Benthic organisms in the bottom sediments will be disturbed by these measurements, but the resultant environmental impact should be negligible due to the small areas that are sampled.

Core drilling operations are conducted by floating drill ships utilizing relatively small drilling equipment. Core drilling affords a possible source of pollution in the form of a blowout, and the danger increases with depth of penetration. However, the probability of a blowout due to coring into an oil reservoir, which would be a pollution source, is low. For example,

1. In the past 10 years, thousands of core holes have been drilled by the petroleum industry (under USGS and Canadian government permits) on the shelves and slopes of all of the U.S. and Canadian coasts, and no pollution has been reported.(C-1)

2. JOIDES deep-water coring program drilled 236 core holes by December, 1970. Maximum depth of subocean penetration was 3,334 feet, and no pollution was reported.

3. Improvements in core drilling techniques and blowout protection can be expected.

4. The number of blowouts during drilling (on land) from 1960 through 1970 has been reported(C-3) to be 106 out of 273,000 wells. Most blowouts are from high-pressure gas rather than oil.

Drilling

Offshore petroleum drilling operations are essentially the same as those for onshore drilling except that the rig is supported by a structure that rests on the bottom of the sea or on a floating vessel rather than on land. The type of offshore structure which supports the drilling operation varies from platforms on piles, jack-up structure and floating vessels to manmade islands. A self-contained platform containing all of the necessary materials and equipment for drilling as well as personnel housing is the accepted method for drilling in prolific, proven areas.

Any spillage of fluids or waste disposal during drilling operations provides a source of pollution. Pollution of offshore waters during normal drilling operations is prevented by installation of drip pans under the rig substructure for collection of mud and oil from the rig floor area. These pans are drained at frequent interval. The drilling mud is water based and is not considered a pollutant.

On some offshore rigs the sump material is gathered and treated on the platform to separate the oil products from water and noncontaminating solids. These waste treatment units typically use chemical treatment as a means of separating the hydrocarbons for further shore processing. On drilling rigs which do not have these facilities, the waste oil products are hauled ashore to be disposed of or processed. Other trash from the rig is put into metal containers and transported to shore for disposal.

The greatest potential for pollution of offshore waters during drilling operations is from a blowout. Once the hydrostatic head required to control formation pressures is inadequate, feed-in from the formations may commence. This loss of pressure may result from either drilling into an unanticipated high-pressure formation or the loss of a hydrostatic balance because of a zone's accepting the drilling fluid.

Blowout-preventer assemblies and other protective equipment and techniques are used to minimize the occurrence of the events. Blowout-preventer assemblies are equipped with rams and closing mechanisms designed to close around the drill pipe or around the casing or to plug the open hole. Alarm devices are used to alert drilling crews to potential blowout conditions. Mud system monitoring equipment is installed with derrick floor indicators while drilling operations are taking place, and adjustments are made in the mud conditions to compensate for the effects of pressure changes. The majority of blowouts occur when pulling and running the pipe. Use of recording pit-level indicators has been helpful in determining that the hole is taking an amount of mud equal to the pipe volume withdrawn. Industry experience has shown that this is an important item in blowout prevention.

Completion

Formation Evaluation and Well-Testing. The evaluation of offshore and onshore wells to determine their commercial potential may be done in several ways. The most accurate diagnostic method of evaluation is a "drill stem test" which involves the transport of formation fluid to the surface through pipe. This information, combined with an analysis of bottomhole pressure, permits an estimate of the quantity of fluids that the formation can produce as well as the type of fluid.

The fluids that are produced during a drill stem test are collected in tanks at the surface. These fluids are recovered by flowing to the surface, by being displaced from the well with drilling fluid, or by collecting them in a chamber placed on the bottom of a drill pipe. The oil, water, drilling mud, and gas are produced from the well and are passed through a separator. The drilling mud is returned to the drilling-fluid tank; the oil not used for laboratory analysis is placed in a waste-oil tank; and the gas other than that collected for analysis is burned by an appropriate flare arrangement.

The initial gas or oil produced from a well cannot be directed into regular production facilities until the necessary tests are completed. The testing time required, of course, varies with each well, but the average for an oil well is two or three hours. For a gas well, the average testing time ranges from two to four hours for a development well and from one to seven days for an exploratory well, depending on the area and the type of formation being tested. Also, the amount of gas or oil initially produced and the rate of flow vary greatly for different wells. Because of the short testing time required for development wells, the initial production of gas or oil is relatively small, but gas from an exploratory well can flow at a rate from a few thousand cubic feet per day to millions of cubic feet per day.

Oil or gas produced during the well-testing programs is passed through the required equipment, such as separators, tanks and vent lines, but must be disposed of ultimately. Well-testing gas is usually burned, emitting carbon dioxide and water vapor, and only small amounts of other contaminants, into the atmosphere. The amount of oil produced during well-testing is usually not a substantial quantity and may be discharged into waste pits and burned, releasing products of the combustion of hydrocarbons and some products of incomplete combustion. This practice is becoming less prevalent and has been outlawed in several states.

If formation evaluation and well-testing are done properly, there should be no impact on the environment other than air emissions.

Setting the Production Casing. After testing is concluded and it has been determined that the drilled well is to be completed as a producing or fluid-injection well, or that operations are to be suspended, the final string of casing is placed in the well and sealed to the penetrated formation with cement. The environmental emissions of this operation are only those due to the preparation of the cement itself and are not likely to be significant in the overall system.

After the production casing is set in place, the running tubing and Christmas tree are installed. The Christmas tree or surface control valve is normally installed at the surface, although underwater installations are being attempted. The casing is then perforated and the flow from the well is established. If operations are to be suspended temporarily, or if the well is to be abandoned, the wellhead is capped or plugged rather than being equipped with a Christmas tree. No environmental emissions are incurred during these operations when properly performed.

Production

The production phase of oil and gas operations covers a longer period in the history of a producing field than the explorative, drilling, and completion activities. Wastes or emissions to the environment can result during routine production operations (waste water, saltwater brines, sand), during stimulation efforts from acidizing, and from accidents.

Waste Waters.(C-4) Waste water can be a source of oil pollution. Waste water is that formation water which is produced from a reservoir along with the oil and separated therefrom by passing the production through separation and treating facilities. Additional treating facilities remove the entrained oil from the separated water but are not 100 percent efficient in removing the oil from the effluent water. The efficiency in removing oil depends on the physical characteristics of a particular oil, the percentage of water in the crude stream, the volumetric throughput and various other forces. After recognizing these characteristics, evaluating the state of the technology and effects of content in produced waste water to an average of not more than 50 parts per million or 0.005 percent (1/200 of 1 percent) prior to disposal into the Gulf. Periodically, samples are taken and subjected to laboratory analysis to insure that this average limit is not exceeded.

There are about 1,893 structures in federal areas offshore Louisiana producing approximately a total of 1 million barrels of oil per day, but waste water is discharged from only about 214 of these structures. Total waste water production is about 420,000 barrels per day; 240,000 barrels per day are transported to shore and 180,000 barrels per day are discharged into the sea. The largest volume of waste water discharged at a single location is about 20,000 barrels per day. The decision to separate, treat, and discharge waste water on the platform or pipe it to shore depends primarily on whether or not space exists on the platform for separating facilities and if pipeline capacity is available. The oil content of waste water discharged in OCS operations in the Gulf of Mexico, which averaged 40.8 ppm in March, 1972, will contribute as much as 7.3 barrels of oil per day. During 1971, approximately 16 barrels of oil may have been introduced into the ocean daily, either from minor spills, or waste discharge.

Saltwater Brines.(C-1) During production, large amounts of saltwater are usually produced as oil fields age. Such water can create pollution problems from producing wells on land or freshwater-covered areas. Its proper disposal has been and continues to be of major concern to producing operators.

According to a study of the Interstate Oil Compact Commission (IOCC), up to 25 million barrels of saltwater are produced daily from the Nation's oil wells. This study shows further that 72 percent of the water produced is being reinjected into the ground, either for secondary recovery of oil or into nonproductive saltwater-bearing zones that have no commercial value. Prior to returning saltwater obtained during production to underground formations, geologic and engineering studies are made to ensure that no damage is done to freshwater horizons. Where proper natural conditions exist, this disposal method is desirable, both from commercial and ecological standpoints. Subsurface disposal, whether for improved recovery or for disposal only, is strictly regulated by state conservation agencies.

The IOCC study also indicates that 12 percent of the salt water extracted during production is put into nonpotable water bodies, approved disposal sites, or is suitable for use in irrigation or for livestock. Another 12 percent is poured into nearby rivers. Disposal of saltwater into freshwater streams is not permitted, although it may be disposed of in saline bays and estuaries and offshore.

Sand Production.(C-1) In some areas, the influx of formation sand into the wellbore presents a major obstacle to production. All methods of controlling sand influx require that all of the sand be cleaned from the wellbore after the well "sands up" and goes off production. This sand normally is oil saturated and must be cleaned or transported ashore to avoid the danger of pollution of offshore waters.

Well Stimulation.(C-1) Acidizing, or pumping acid into a carbonate or sand formation, and hydraulically fracturing a productive interval account for more than 80 percent of all of the well-stimulation treatments. Using the acidizing technique, several hundred gallons of hydrochloric acid, organic acids or hydrofluoric acid are pumped at a low rate into the production formation. After treatment, the well is placed back on production and the spent acid, which is neutralized by salt water, is separated from the crude oil and is disposed of in the same manner as the saltwater produced from the well.

Blowouts.(C-4) Over 14,000 offshore wells have been drilled in the period from 1937 to 1970 in the United States federal and state waters.

Of these wells, approximately 9,000 have been drilled in the OCS with more than one-half of them completed as productive for oil or gas. During this period, 25 blowouts have been experienced. The three serious blowouts are described here to indicate the scope of the environmental problems created by these events.

Santa Barabara Spill.(C-5) On January 28, 1969, a blowout occurred below Union Oil Company's fixed drilling Platform A in the Santa Barbara Channel, about six miles southeast of Santa Barbara, California. This blowout and spill occurred through a fissure in the ocean floor adjacent to the well after gas under high pressure from a deep reservoir was accidentally injected into shallow reservoir sands. The resulting buildup of pressure in the shallow reservoir sands soon exceeded the strength of the overlying rock layer and caused a rupture to occur. The rupture formed a fissure zone, thus opening an avenue of communication between the hydrocarbon reservoir and the seabottom.(C-6)

Total initial spillage was estimated by the Geological Survey to be 10,000 barrels, with subsequent leakage amounting to about 8500 barrels. A number of factors relate to the final disposition of the spilled oil. The report states that slow solubility and surface flotation of the crude oil allowed rapid loss of volatile compounds which reduced potential toxicity of the oil. It should be pointed out that no chemical analyses were included to support this statement. M. Blumer and associates (personal communication) had an opportunity to analyze oil that arrived at Santa Barbara beaches and found that, in spite of exposure at sea, gas chromatography showed the presence of benzenes, naphthalenes, tetralines, and diphenyls. Thus, the oil had lost little of its acute, and probably none of its long-term toxicity through exposure at sea. Geological studies revealed that "much of the oil deposited at the sediment-water interface was removed from the area of initial deposition and was retransported into deeper water".(C-5)

Elsewhere, the same author said that within four months after the accident the entire Santa Barbara basin was covered with oil from the spill.(C-7)

In summary, the study reiterates that damage to biota was not widespread but limited to several species. The study hypothesizes that "the biota of the area had a high tolerance to oil built up by almost continuous exposure to small amounts of similar oil from natural seeps over long periods."(C-5) Further, "the presence of oil in the area may have resulted in a normally high population of oil degrading bacteria".(C-5) This hypothesis is supported by the work of marine microbiologist Zobell.(C-8)

The study was complicated by several factors. First, the area is noted for natural oil seepage which made it difficult to obtain comparative data in regard to "normal conditions in the area before or between spills resulting from drilling activity. Second, the largest recorded flood in Southern California history occurred almost simultaneously with the spill resulting in a large runoff of freshwater and sediments into the Santa Barbara Channel, creating reduced salinities, high sedimentation rates, and a probable increase in pesticide levels that washed into the Channel from citrus groves. Third, there was an overall general lack of knowledge of the ecology of the area. Fourth, in spite of numerous statements concerning toxicity, solubility, aromatic content, weathering, and oxidation of the spilled oils, results of chemical analyses were not incorporated into the publication of the studies.

Chevron Fire and Oil Spill.(C-9) On February 10, 1970, Chevron Oil Company's platform MP 41C, caught fire. Platform "C" is located in 40 feet of water about 75 miles southeast of New Orleans, Louisiana. On March 10, 1970, the fire was extinguished, and oil that previously had been consumed by the fire began escaping into the Gulf of Mexico. Crude oil and gas continued to escape until the last of the wild wells was brought under control on March 31, 1970. Reliable estimates placed the total volume of oil spilled at about 30,000 barrels.

Oil from the spill was a light crude, containing a high proportion of lower boiling constituents and a relatively low concentration (about 10 percent) of aromatic hydrocarbons. Through a fortunate set of circumstances, the oil was sprayed high into the air under great pressure and frequently into considerable wind, so that far more evaporation took place than is usually estimated to occur during a spill. Samples collected 500 feet from the platform and analyzed by Federal Water Quality Administration (FWQA) laboratories showed a loss in volume of 16 percent, all in the lighter ends. Also, about 5,000 barrels of oil were removed by skimming. Some 1,500 barrels of chemical emulsifier were used during the spill as well.

Almost no field observations or collections were made to determine ecological damage that may have resulted from the spill. The FWQA, from laboratory bioassays, reported that 72 hours with 13,300 parts per million (ppm) of oil did not kill brackish water species of killifish. The Louisiana State University, working with other Louisiana crudes and white and brown shrimp, reported no mortality after 48 hours exposure to 1,000 ppm oil, 50 percent mortality with 7,500 ppm, and 100 percent with 15,000 ppm. However, emulsifier/oil combinations were roughly tenfold more toxic than oil alone when tested on shrimp.

The only other biological observations made were that samples from oil slicks were found by Louisiana State University scientists to contain large numbers of oil degrading yeasts, and that monitoring during the spill by Louisiana Wildlife and Fisheries Commission showed no mortality or oily taste in oysters east of the Mississippi River.

Thus, in concluding remarks, it was stated that there were no confirmed reports to date of environmental damage that could have been directly attributed to the Platform "C" oil spill. A number of fortunate circumstances serves to mitigate potential damage from this spill:

1. Extreme rate of evaporation took place as mentioned above

2. Considerable dispersion and dilution took place because of the platform distance offshore, wind and sea conditions, and use of emulsifiers

3. Direction of wind during the spill was predominately offshore, thus blowing slick and emulsions further away from land, and

4. The saltwater/freshwater interface (riptide) caused by the overflow of the Mississippi River, then at flood stage, appeared to provide a very effective barrier and prevented oil from reaching the shores and marshes of the lower delta.

The authors state that assessment of biological damage was complicated in the area by the multitude of sources of oil and small, but chronic leakage. Numerous oil slicks from sources other than Platform "C" were observed during the incident, and analysis of sediment samples revealed widespread presence of oil. They hypothesize that, since the area has been subject to chronic oil exposure for 20 years, it is possible that the biota may already have been altered and the most oil-sensitive species eliminated.

Shortcomings of this report are obvious: very little field sampling was done; almost no chemical analysis of water, sediment, or biological material was performed or reported; efforts to evaluate the environmental effects of the spill were generally limited to detecting the immediate impact on commercial fishery species. Ecologically significant damage to biota could have occurred and remained undetected.

In public hearings held by the Department of the Interior in New Orleans on September 8 and 9, 1971, concerning a proposed oil and gas lease sale offshore Louisiana, Dr. John G. Mackin, marine biologist at Texas A&M testified that his study revealed:

> "One, the Chevron platforms 41-C fire liberated crude petroleum in the shelf and Bretton Sounds areas to the northeast and east of the Mississippi Delta. Two, so far as can be determined, none of this oil reached the shore or marsh. Three, no effects of the spill can now be detected so far as the biology communities are concerned. Four, no effect on the fisheries was found. Five, the spill did not destroy birds or wildlife as have some other widely publicized spills. As a peculiar fact, destruction of birds has not been a feature in any spill in Louisiana waters that I have any knowledge of."

Shell Oil Spill. On December 1, 1970, a blowout occurred on Shell Oil Company's Platform B in Block 26, about seven miles offshore South Timbalier Bay, Louisiana. About 53,000 barrels of crude oil were spilled on waters near the 50-foot depth contour. With reservation, a summary of the study(C-10) on the fate and effects of this spill was included in the Draft Statement. It was noted that sampling methods were questionable and that the results were somewhat inconclusive.

At the OCS Public Hearing of August 22 and 23, held in New Orleans, Shell Oil Company presented written testimony including critiques of the report(C-10) by three scientists who are recognized authorities in the areas covered.

These three critiques leave little doubt that the integrity of the fate and effects study is questionable. Therefore, the summary of the study which was presented in the Draft Statement has not been included in the Final Statement. All material presented at the OCS Public Hearing is available for inspection at the Bureau of Land Management, Washington, D.C. office. Oppenheimer(C-11) noted a "(s)light accumulation of oil on beaches. No report on adverse environmental damage to biota have been found", as a result of the Shell spill.

Environmental Emissions

Air

Sources of Emissions. The principal activities giving rise to air pollution in the exploration, drilling, and production of oil and gas are blowouts and well-testing. Blowouts will inject hydrocarbons directly into the atmosphere and additional hydrocarbons are emitted by evaporation of the oil that is dispersed on the water. The extent of the emissions will depend upon the chemical composition of the crude oil and will increase as the fraction of light ends in the crude increases. If a fire occurs in addition to the blowout, combustion products--CO, NO_x, SO_2, and particulates--will also be released to the air environment.

Over the ten-year period from 1962 to 1972, 1.9 billion barrels of oil and condensate were produced from the OCS in the Gulf of Mexico.(C-4) During this period, nine platform accidents involving drilling or producing operations resulted in the spillage of 96,300 barrels of oil, or 5×10^{-3} percent of the amount produced. An additional amount of oil is discharged to the environment in the waste water that is produced. Current OCS regulations permit only an average discharge of 50 ppm of oil in the waste water. In federal areas offshore Louisiana, approximately 1 million barrels of oil are produced per day along with 420,000 barrels of waste water. Only 180,000 barrels of treated water are discharged to the sea. Oil discharged by this route is (50×10^{-6}) (180,000) = 9 barrels per day or about 1×10^{-3} percent of the production.

During well-testing, the gas or oil produced is burned and the products of combustion are released to the environment. With adequate pollution control devices on the burning equipment, these emissions should be very small.

An additional source of air pollution is the exhausts from the diesel-powered vessels used for seismic survey and drilling rig engines. These emissions are expected to be minor.

Estimate of Quantities of Emissions. For the purposes of this study, it will be assumed that the sources of emissions during exploration, drilling and production are the same for offshore and onshore operations. It is further assumed that 25 percent of the oil that is discharged through blowouts and spills is ignited and burns in a manner similar to that in oil-fired burners. Of the remaining 75 percent, 20 percent is assumed to be a volatile fraction that will evaporate into the air. The total emissions from the oil discharges are:

	Emissions, pounds per barrel of oil discharged		
	Fires(a)	Evaporation	Total
Particulate	1	--	1
SO_2	19	--	19
HC	0.1	38	38.1
CO	0.01	--	0.01
NO_x	2.5	--	2.5

(a) Burning assumed to be the same as residual oil firing in industrial burners. Emission factors from "Compilation of Air Pollutant Emission Factors", (revised), U.S. Environmental Protection Agency, Office of Air Programs, Research Triangle Park, North Carolina, February, 1972.

Water

Sources of Effluents. In offshore operations, the major sources of water pollution are the hydrocarbons released during blowouts and spills, and hydrocarbons discharged with treated waste water. Human waste treatment systems are now required, so that water pollutants other than hydrocarbons are expected to be negligible.

There are several sources of water pollution in onshore operations.(C-12) The construction of roads for access into prospective petroleum-producing areas could affect when drainage patterns are disturbed or when erosion is possible. Canal dredging can avoid serious or permanent water quality impacts, but can result in temporarily increased turbidity and sediment suspension.

The major environmental emissions occur through the entry of oil, chemicals, brine, and waste materials into the water cycle. Spills and leaks allowing such substances to enter the surface or ground water systems can result from human error and neglect, mechanical failures, burning pits and open ditches, and from blowouts. During production, large amounts of saltwater are produced daily from the nation's oil wells. Subsurface disposal is strictly regulated by state water resource agencies and disposal of saltwater is not permitted in freshwater streams.

Estimates of Quantities of Effluents. Based upon the discussion of air pollution, it is estimated that 6×10^{-3} percent of the oil produced is discharged to the environment. If the amount of discharged oil that is released to the air environment is subtracted from this total, about 4×10^{-3} percent of the oil produced appears as a water pollutant.

Saltwater brines were discussed in the Technology Section of this appendix. From the data presented, it appears that up to 4 percent or about 1 million barrels of the saltwater brines may be discharged directly into the environment. Chloride concentrations range from 12 to 50 pounds per barrel and total dissolved solids are on the order of 100 pounds per barrel.

Land

Environmental impacts to the land from exploration, drilling, and production arise through the use of land for the wells and rigs, and for waste disposal pits for oil and brine. No estimate has been made in this study of the amount of land that is being used for waste disposal. About 1/4 acre is used for each oil well. If it is assumed that an oil well produces about 6,200 barrels per year, then the land commitment would be 0.05 acre-hour per 10^6 Btu. This average production value per well is low for offshore operations and the land use per well is higher offshore, since the same offshore rig can service several wells. Hence, the overall land commitment for a unit energy output would be lower for the offshore production.

Other Impacts--Occupational Health

The work-injury rates for the exploration, drilling, and production of oil and natural gas for 1969(C-13) are 9.7 disabling injuries for each million employee-hours worked and 983 days of disability resulting from the disabling work injuries for each million employee-hours worked. There were 450,000 employees in the petroleum and natural gas industry in 1969 and a total of 939 million man-hours were worked.(C-14) Within the industry there were 95 fatal injuries which represents a fatality rate of 0.1 per million man-hours. There were 9,023 nonfatal injuries in 1969 and a nonfatal injury rate of 9.61 per million man-hours.

In 1969, the total production of crude oil was 3.3 billion barrels(C-14) or a total of 20.8×10^{15} Btu's if it is assumed that each barrel of crude oil is equivalent to 6.3×10^6 Btu's. The U.S. gas supply in 1970 amounted to 22.5×10^{15} Btu's.(C-15) Combining the oil and gas estimates, a total of about 43×10^{15} Btu's are produced annually by the petroleum and gas industry. The impact of oil and gas production on occupational safety and health are: fatalities, $95/43 \times 10^9 = 2.2 \times 10^{-9}$ per 10^6 Btu's; nonfatal injuries, $9{,}023/43 \times 10^9 = 2.1 \times 10^{-7}$ per 10^6 Btu's; and time lost $1.49 \times 10^6/43 \times 10^9 = 0.35 \times 10^{-4}$ man-days lost per 10^6 Btu's. (983 man-days lost per million man-hours x 939 million man-hours + 95 fatalities x 6,000 days lost per fatality = 1.49×10^6 man-days lost.)

Pollution Controls

Methods

Pollution control systems(C-16) for gas and oil exploration, drilling, and production include the safety systems which control nonroutine releases; water, soil, and gas treatment systems and operating practices to control the routine pollutants; and sewage treatment systems to control human wastes. The safety devices for offshore operations which are required by OCS regulations include subsurface safety devices, high-low pressure shut-in controls, high liquid level shut-in controls, pressure relief valves, automatic fail-close valves at the wellhead, automatic fire-fighting systems, automatic gas detector and alarm systems, and other safety devices on production equipment; high-low pressure sensing devices on pipelines; and blowout preventers, related well-control equipment, and mud system monitoring equipment on drilling wells. Since some of this equipment has been in use for a period of time less than a year, it is not possible to assess quantitatively its effectiveness in reducing pollution.

Burners are used to dispose of gas, oil, and emulsions and can be operated without smoke,(C-16) reducing particulate emissions. Waste water treatment systems using filtration, skimmers, and centrifugal separators are available for the removal of brine, oil, and suspended solids.(C-17) Drilling muds are neutralized before they are discharged into the ocean from offshore operations. Drill cuttings and sand are processed to remove oil before they are disposed of in the ocean. Electrocatalytic units or sewage treatment plants are used on offshore platforms to control human wastes.

Costs

On an industry-wide basis, the offshore operators have estimated that pollution control and safety devices required to meet the OSC-8 guidelines will cost between $100,000,000 to $150,000,000.(C-18, C-19) Separation of environmental costs from safety costs cannot readily be made.

Brine disposal costs have been estimated to run about 2 percent of net oil sales for onshore operations.(C-20)

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APPENDIX D

ENVIRONMENTAL AND ECONOMIC CONSIDERATIONS INVOLVED IN OIL SHALE DEVELOPMENT

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APPENDIX D

ENVIRONMENTAL AND ECONOMIC CONSIDERATIONS INVOLVED IN OIL SHALE DEVELOPMENT

Oil shale deposits in the Green River Formation, underlying about 17,000 square miles within an area of 25,000 square miles, in Western Colorado, Eastern Utah, and Southwestern Wyoming, comprises one of the immense known potential resources of fossil fuels. Total known resources have been estimated at upwards of 2 trillion barrels of oil equivalent. Of this immense total, some 80 billion barrels are estimated to be recoverable at cost levels estimated in the range of $4.00 to $6.50 per barrel. The growing need for new sources of liquid fuels to meet the vast increases in U.S. demand foreseen over the next several decades has intensified interest in the early commercial developments of these deposits.

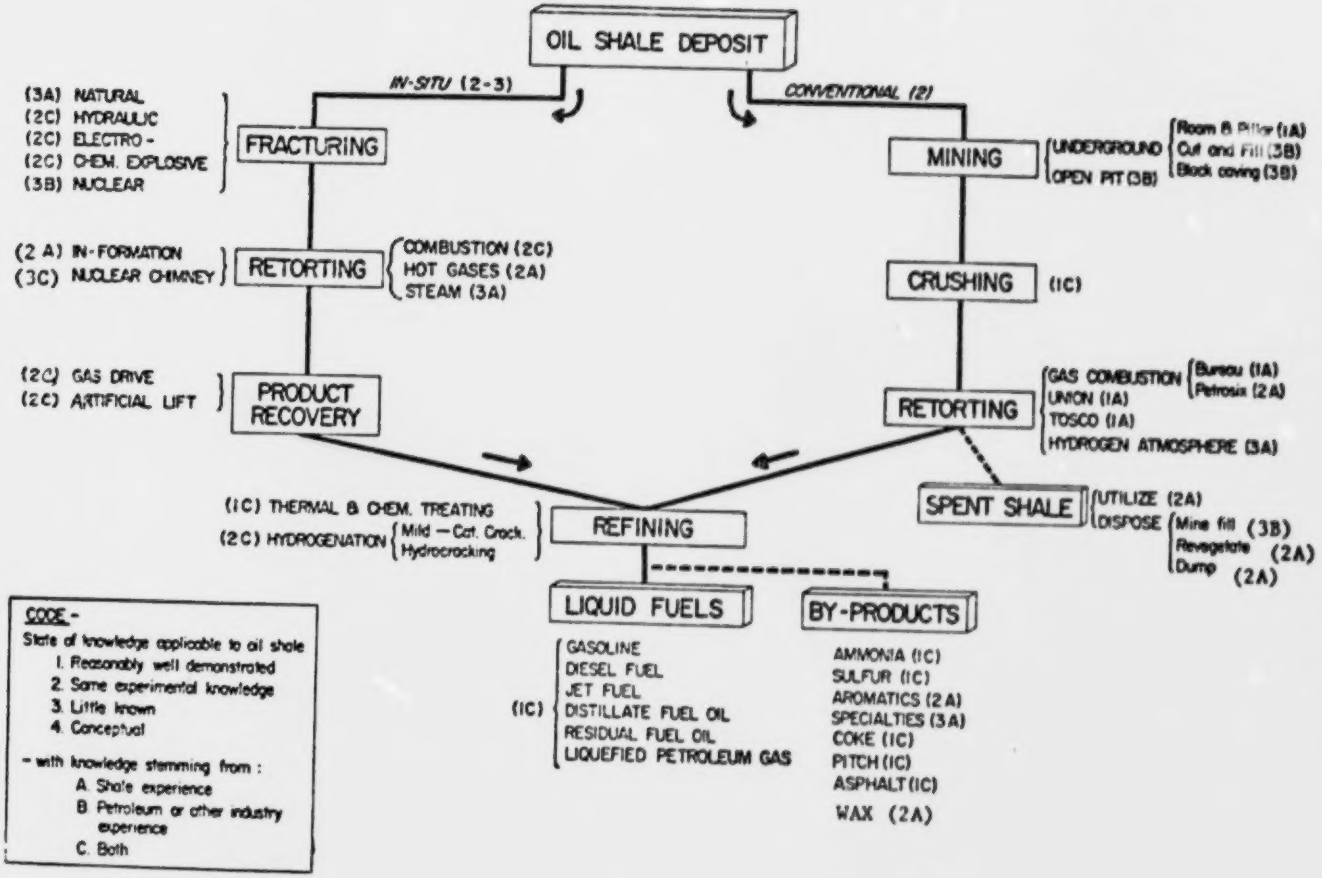
The development of these resources will have a substantial and largely irreversible impact on the environment of the region, as well as potential impacts on adjacent areas. The U.S. Department of Interior has recently completed an environmental statement for a proposed prototype oil shale leasing program which would involve two leases each in Colorado, Utah, and Wyoming, including no more than 5,120 acres each. Proposed methods of development are to include:

1. Underground mining, with underground disposal
2. Underground mining, with surface disposal
3. Strip mining with backfill
4. In-situ operations.(D-1)

The technology involved in mining followed by surface processing of oil shale and shale oil is reasonably well established, but the possibilities of in-situ processing are still in the experimental and research stages. Present status of knowledge on various routes to liquid fuels from oil shale is shown in Figure D-1.

Much of the data used to provide estimates of the potential environmental emission of the commercial development of a 1,000,000 barrel per day liquid-fuel recovery from oil shale is based on information and data taken from the U.S. Department of Interior study.

A flow diagram of a 50,000 barrel-per-day underground oil shale mine and processing unit is shown in Figure D-2. A flow diagram of a retorting system is shown in Figure D-3 (six individual, 56-foot diameter retorts would be required for a 50,000 barrel-per-day plant), while


OIL SHALE DEPOSIT
IN-SITU (2-3)
CONVENTIONAL (2)
(3A) NATURAL
(2C) HYDRAULIC
(2C) ELECTRO-
(2C) CHEM. EXPLOSIVE
(3B) NUCLEAR
FRACTURING
(2 A) IN-FORMATION
(3C) NUCLEAR CHIMNEY
RETORTING
COMBUSTION (2C)
HOT GASES (2A)
STEAM (3A)
(2C) GAS DRIVE
(2C) ARTIFICIAL LIFT
PRODUCT RECOVERY
MINING
UNDERGROUND
Room & Pillar (1A)
Cut and Fill (3B)
Block caving (3B)
OPEN PIT (3B)
CRUSHING
(1C)
RETORTING
GAS COMBUSTION
Bureau (1A)
Petrosix (2A)
UNION (1A)
TOSCO (1A)
HYDROGEN ATMOSPHERE (3A)
SPENT SHALE
UTILIZE (2A)
DISPOSE
Mine fill (3B)
Revegetate (2A)
Dump (2A)
(1C) THERMAL & CHEM. TREATING
(2C) HYDROGENATION
Mild — Cat. Crack.
Hydrocracking
REFINING
LIQUID FUELS
(1C)
GASOLINE
DIESEL FUEL
JET FUEL
DISTILLATE FUEL OIL
RESIDUAL FUEL OIL
LIQUEFIED PETROLEUM GAS
BY-PRODUCTS
AMMONIA (1C)
SULFUR (1C)
AROMATICS (2A)
SPECIALTIES (3A)
COKE (1C)
PITCH (1C)
ASPHALT (1C)
WAX (2A)
CODE -
State of knowledge applicable to oil shale
1. Reasonably well demonstrated
2. Some experimental knowledge
3. Little known
4. Conceptual
- with knowledge stemming from :
A. Shale experience
B. Petroleum or other industry experience
C. Both

August 1972

FIGURE D-1. OIL SHALE UTILIZATION - ROUTES AND STATE OF KNOWLEDGE

Source: Reference D-1.

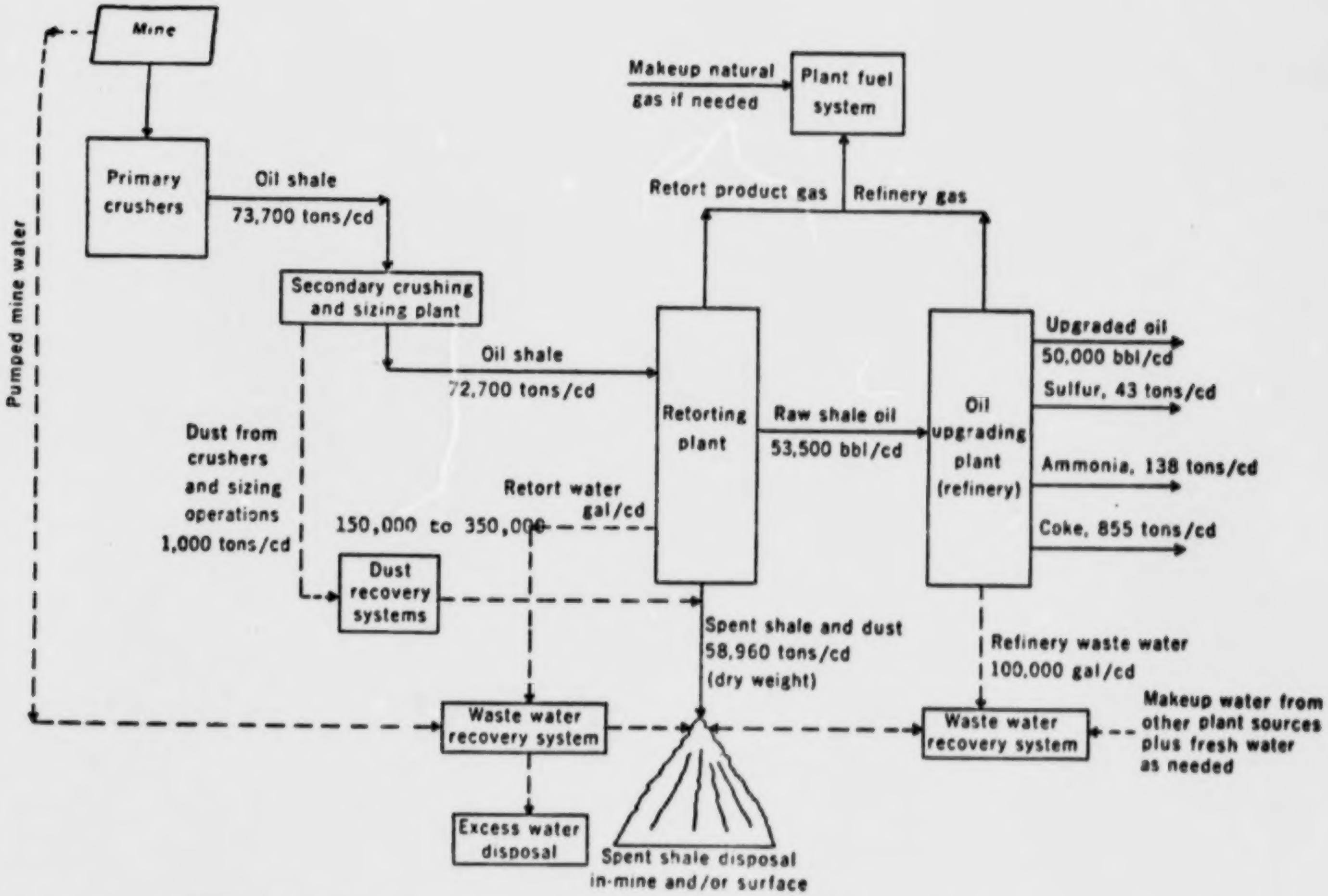

Mine
Primary crushers
Oil shale
73,700 tons/cd
Secondary crushing and sizing plant
Oil shale
72,700 tons/cd
Dust from crushers and sizing operations 1,000 tons/cd
Dust recovery systems
Retort water 150,000 to 350,000 gal/cd
Pumped mine water
Makeup natural gas if needed
Plant fuel system
Retort product gas
Refinery gas
Retorting plant
Raw shale oil
53,500 bbl/cd
Oil upgrading plant (refinery)
Upgraded oil 50,000 bbl/cd
Sulfur, 43 tons/cd
Ammonia, 138 tons/cd
Coke, 855 tons/cd
Spent shale and dust 58,960 tons/cd (dry weight)
Refinery waste water 100,000 gal/cd
Waste water recovery system
Excess water disposal
Spent shale disposal in-mine and/or surface
Waste water recovery system
Makeup water from other plant sources plus fresh water as needed

FIGURE D-2. FLOW DIAGRAM OF 50,000 BARREL PER CALENDAR DAY (cd) UNDERGROUND OIL SHALE MINE AND PROCESSING UNIT

Source: Reference D-1.

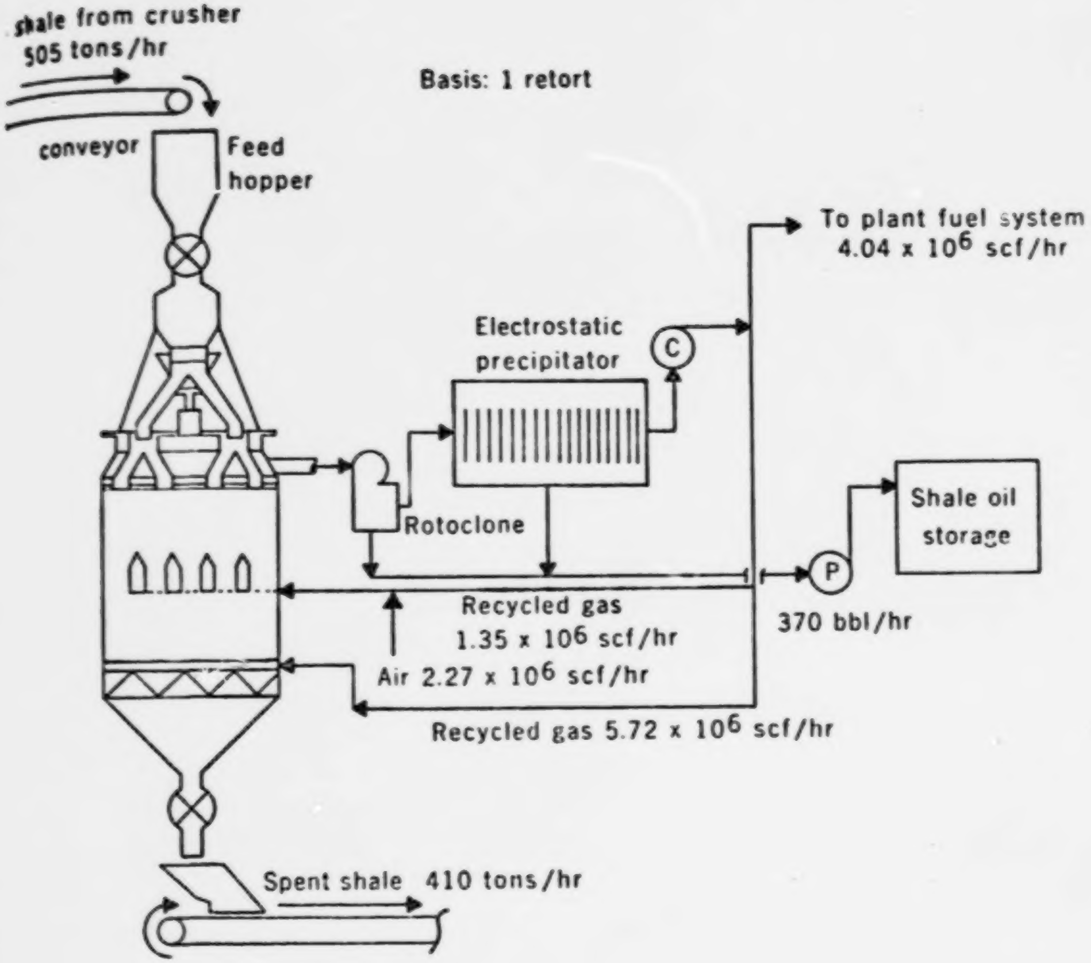

shale from crusher
505 tons/hr
Basis: 1 retort
conveyor
Feed
hopper
To plant fuel system
4.04 x 10⁶ scf/hr
Electrostatic
precipitator
C
Rotoclone
Shale oil
storage
P
370 bbl/hr
Recycled gas
1.35 x 10⁶ scf/hr
Air 2.27 x 10⁶ scf/hr
Recycled gas 5.72 x 10⁶ scf/hr
Spent shale 410 tons/hr

FIGURE D-3. SCHEMATIC FLOW DIAGRAM OF RETORTING SYSTEM

Source: Reference D-1.

Figure D-4 shows a flow diagram for the upgrading plant, producing semirefined oils suitable for pipeline transmission to a conventional petroleum refinery.

A flow diagram of an envisioned 50,000 barrel-per-day in-situ recovery system is shown in Figure D-5. It should be noted that substantial quantities of water are produced in conjunction with the recovery of oil and gas vapors, which would require treatment. The physical characteristics of the shale-oil recovered by in-situ processing also would be substantially different from that produced by presently known retorting methods. Tests run on oil recovered in limited experiments indicate that the oil would be appreciably lighter and with a much lower pour point, making it potentially suitable for shipment to a conventional petroleum refinery without further processing.

Land Requirements

Estimated land requirements for oil shale processing by different methods are shown in Table D-1.

Surface mining would have the greatest initial disturbance. Assuming a 30-year development period the cumulative land requirements might be as much as 66,500 acres. With backfill of spent shale and restoration of the land, this might be reduced to 26,750 acres.

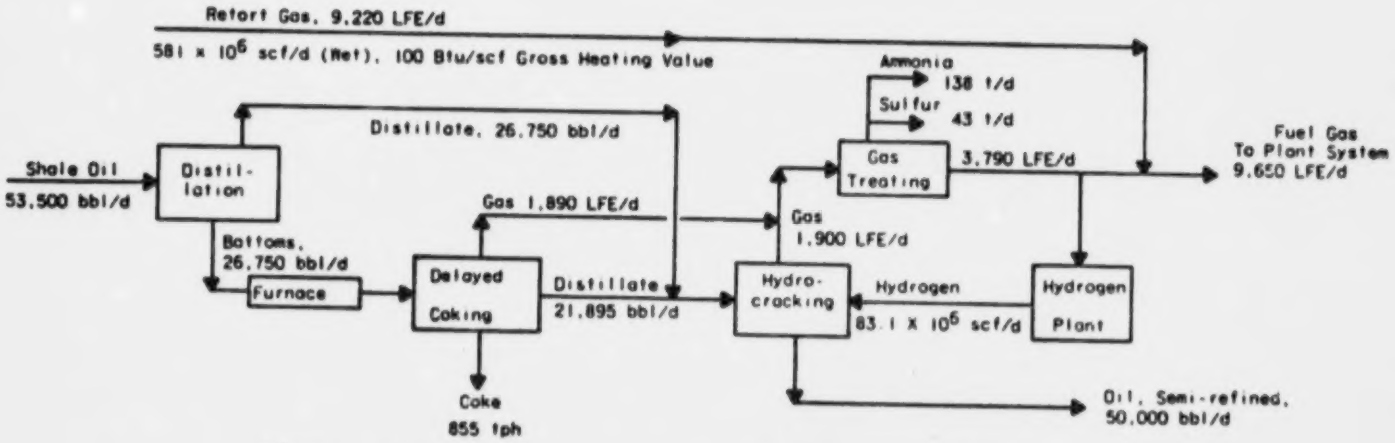
Underground mining with surface disposal might be as much as 44,000 acres. By utilizing underground disposal for 60 to 80 percent of the spent shale, this could be reduced to about 22,000 acres.

In-situ processing under full-scale operation would have from 15,500 acres to 35,800 acres in active development at any given time depending on the rate of recovery per well drilled. Restoration of depleted areas would be a continuing process.

In addition to actual land used in mining, spent shale disposal, and/or in-situ operations, land would be required for other processing operations, storage facilities, and rights-of-way for pipelines, utilities, and roads. This might require as much as 1,700 to 2,000 acres per site, or from 34,000 to 40,000 acres total. Also, urban land requirements to handle the increase in temporary and permanent employment in the region might require an additional 20,000 acres.

This would indicate a total land use requirement of upwards of 75,000 acres by 1985, and a continuing need for about 2,000 new acres annually. Thus, the land use would entail about 0.5 percent of the 25,000 square mile region, with a continuing requirement of 0.01 percent per year. Land use per barrel of daily capacity would be about 0.075 acre.

Disposal of spent shale, as well as overburden in the case of a surface mine, will create a major permanent impact on the land surface.


Retort Gas, 9,220 LFE/d
581 x 10⁶ scf/d (Net), 100 Btu/scf Gross Heating Value
Shale Oil
53,500 bbl/d
Distil-lation
Distillate, 26,750 bbl/d
Bottoms,
26,750 bbl/d
Furnace
Delayed Coking
Gas 1,890 LFE/d
Distillate
21,895 bbl/d
Coke
855 tph
Hydro-cracking
Gas
1,900 LFE/d
Gas Treating
Ammonia
138 t/d
Sulfur
43 t/d
3,790 LFE/d
Fuel Gas
To Plant System
9,650 LFE/d
Hydrogen
83.1 X 10⁶ scf/d
Hydrogen Plant
Oil, Semi-refined,
50,000 bbl/d

1/ LFE is Liquid Fuel Equivalents With Gross Heating Value 6 3 X 10^6 Btu

FIGURE D-4. 50,000 BARREL PER CALENDAR DAY REFINERY

Source: Reference D-1.

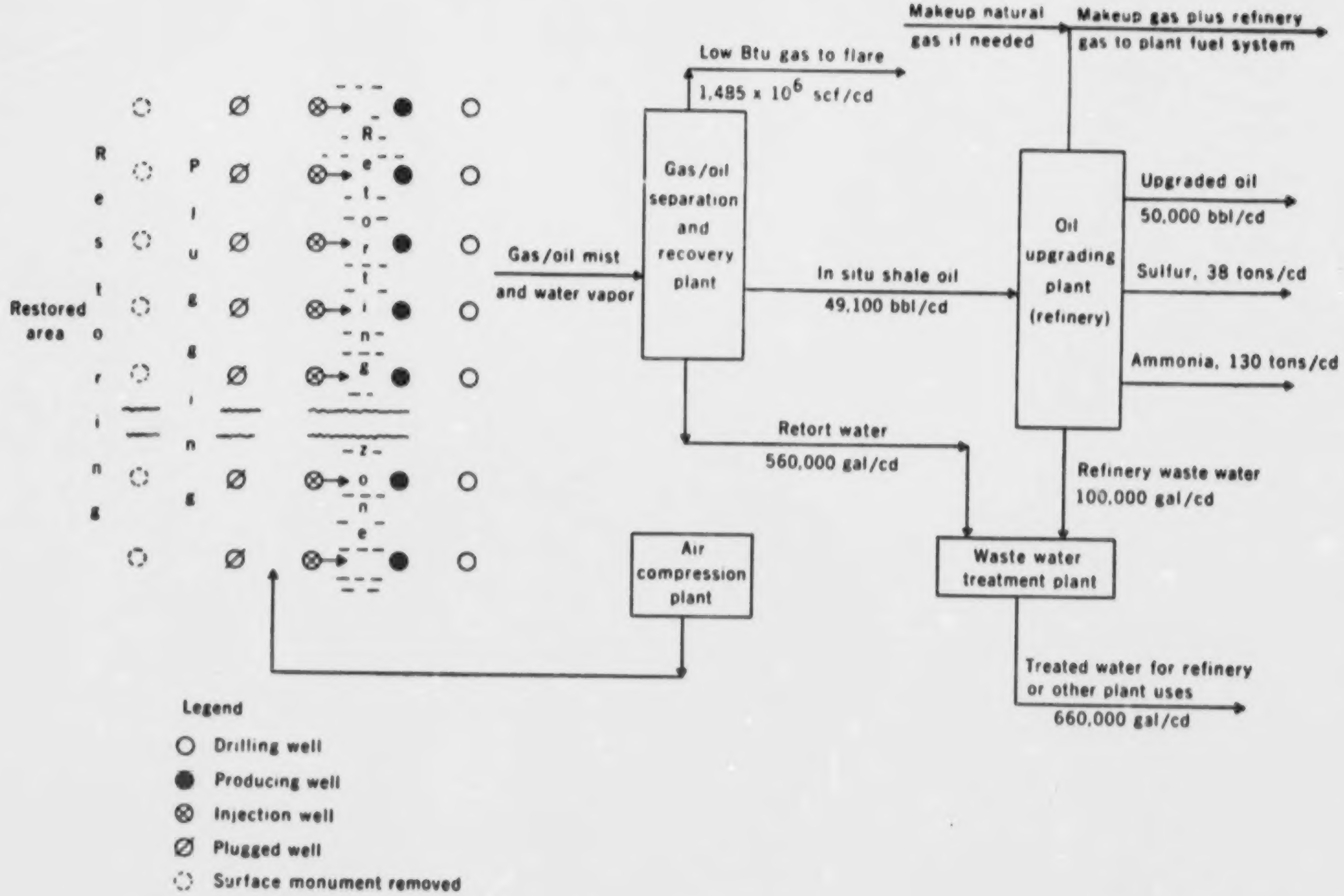

Restored area
Restoring
Plugging
Retorting
Zone
Gas/oil mist and water vapor
Gas/oil separation and recovery plant
Low Btu gas to flare
1,485 x 10^6 scf/cd
In situ shale oil
49,100 bbl/cd
Retort water
560,000 gal/cd
Air compression plant
Makeup natural gas if needed
Makeup gas plus refinery gas to plant fuel system
Oil upgrading plant (refinery)
Upgraded oil
50,000 bbl/cd
Sulfur, 38 tons/cd
Ammonia, 130 tons/cd
Refinery waste water
100,000 gal/cd
Waste water treatment plant
Treated water for refinery or other plant uses
660,000 gal/cd
Legend
○ Drilling well
● Producing well
⊗ Injection well
Ø Plugged well
◌ Surface monument removed

FIGURE D-5. FLOW DIAGRAM OF 50,000 BARREL PER CALENDAR DAY IN SITU RECOVERY SYSTEM

Source: Reference D-1.

TABLE D-1. LAND REQUIREMENTS FOR OIL SHALE PROCESSING

Function	Land Required, acres
Mining and Waste Disposal	
Surface Mine[(a,b)] (100,000 bbl/day)	
Mine Development	30 to 85 per year
Permanent Disposal, overburden	1,000 (total)
Temporary Storage, low-grade shale	100 to 200 (total)
Permanent Disposal, processed shale	140 to 150 per year
Surface Facilities[(c)]	200 (total)
Off-Site Requirements[(e)]	180 to 600 (total)
Underground Mine[(b)] (50,000 bbl/day)	
Mine Development (surface facilities)	10 (total)
Permanent Disposal	
All processed shale on surface	70 to 75 per year
60 percent return of processed shale underground	28 to 30 per year
Surface Facilities[(c)]	140 (total)
Off-Site Requirements	180 to 225 (total)
In-Situ Processing (50,000 bbl/day)	
Surface Facilities[(c)]	50 (total)
Active Well Area and Restoration Area[(d)]	100 to 900
Off-Site Requirements	180 to 600 (total)

(a) Area required is dependent upon the thicknesses of the overburden and oil shale at the site. Acres shown are for a Piceance Creek Basin site, with 550 feet of overburden and 450 feet of 30 gallon/ton shale (approximately 900,000 bbl/acre).

(b) Assumes 30 gallons per ton oil shale and a disposal height of 250 feet.

(c) Facilities include shale crushing, storage and retorting (excluded for in-situ processing), oil upgrading, and storage, and related parking, office, and shop facilities.

(d) See Vol. III, Figure (III-11) for conceptual view of surface utilization.

(e) Includes access roads, power and transmission facilities, water lines, natural gas and oil pipelines; actual requirements depend on site location. A 60-foot right of way for roads requires a surface area of about 8 acres per mile. Utility and pipeline corridors 20 feet in width require 2.4 acres per mile.

Source: Reference (D-1).

During the early years of open-pit mining, all of the overburden and spent shale from retort operations would have to be disposed off-site. Because of the increase in volume of the spent shale over the original oil shale in place, a substantial portion (20 to 40 percent) of the spent shale would need to be disposed of above ground even with good compaction of the spent shale. The immense volumes involved would need to be disposed in carefully selected sites, probably dry canyons. The filling of these canyons would affect the topographic and watershed characteristics of the area involved. Considerable research and experimental testing has been done on methods of compaction, stabilization of the disposal piles, and revegetation. However, many years would be required to fill canyons to the desired ultimate height and revegetate and otherwise restore the affected area. Interim actions would be required to prevent or minimize wind and water erosion as well as leaching of the spent shale. Small-scale experiments by Nevens, et al(D-2) have indicated a natural surface cementation reaction that can minimize erosion and leaching effects. The construction of upstream diversion dams and canals or culverts to carry runoff water past disposal sites has been suggested as a means of obtaining better erosion control during the build-up of the waste disposal pile. Sediments eroding from the pile would be trapped through construction of downstream ponds capable of retaining the run-off waters for the necessary settling time. Water from these downstreams ponds, if high in dissolved solids from leaching of the pile, could be used for compaction of the pile; or in other appropriate process operations. If water in excess of operational needs is obtained, other disposal methods will be required to prevent increased salinity in the Colorado River System.

Impact on Air Quality

The principal sources of air pollution would be solid particulates resulting from mining and spent shale disposal operations, dust produced during crushing and retorting operations, burning of gases from retorting and refining operations and the generation of electric power, and the dust and vehicle emissions from construction and mining operations.

Estimates by the U.S. Department of Interior(D-1) for major air pollutants based on a 1,000,000 barrel-per-day scale of operations are as follows:

Dust -- 440 tons per day ≈0.88 lb/bbl oil (assuming 98 percent primary dust capture efficiency)

SO_2 -- 460 to 680 tons per day ≈0.92 to 1.36 lb/bbl oil

NO_2 -- 80 to 120 tons per day ≈0.16 to 0.24 lb/bbl oil.

The operation would, of course, be located in various areas having differing weather conditions. Temperature inversions are typical of the Colorado region, so air quality in certain instances may exceed ambient air standards. Weaver(D-3) in a recent study has calculated the possible impact on ambient air quality in the central Piceance Creek Basin for a minimum sized plant. Peak ground level concentrations under certain inversion conditions are shown to exceed Colorado air quality standards by appreciable amounts over substantial distances.

The U.S. Department of Interior in its recent report has stated:(D-1)

> "It is clear...that source emissions to the atmosphere must be so controlled that pollutants would not accumulate under inversion conditions. Wherever feasible, processing facilities should be located on upland services rather than in valleys and canyons."

For Utah locations they conclude that uncontrolled pollutants would tend to affect the Rangely, Colorado, population center. Conversely, inversion conditions in Wyoming are expected to present less of a problem.

The residual concentrations of sulfur are estimated to be 230 to 340 tons per day for a 1 million barrel-per-day operation. This level is calculated to meet minimum standards in the region. Most of these sulfur emissions would occur from burning of the low Btu stack gases from retort operations. Actual levels of sulfur present in these gases would be between 0.9 and 1.1 pounds per million Btu for internal combustion processes, about 5 pounds per million Btu for the indirectly heated process, and 2.8 pounds per million Btu for in-situ combustion. In comparison, the Environmental Protection Agency standards for stationary sources is 0.6 pound per million Btu, while Colorado standards are still lower. It would, therefore, be necessary to establish sulfur removal facilities either through precombustion processes, or stack gas removal of SO_2. Technology exists to accomplish the former, while numerous methods for stack gas removal of SO_2 are in the developmental stage.

The estimated NO_x emissions are primarily a result of combustion techniques, although some additional NO_x also may be formed from chemically bound nitrogen in liquid or solid fuels that may be used.

Impact on Water Quality

The extent of the impact on water quality cannot be measured with any degree of accuracy prior to actual development of a specific operation. Aquifer characteristics and quality of the water produced would be major determinants. Considerable data have been developed for the Piceance Creek Basin in Colorado and estimates of the transmissivity of the water-bearing zones have been made for most of the sites nominated in Colorado under the proposed leasing program.(D-1)

Water supply and demand balances have been developed for two hypothetical mining operations in Colorado as shown in Figure D-6. Flow

	New Water, Acre Feet per Year	
	Underground Mine 1/	Surface Mine 2/
Water Required for:		
Crushing	150- 220	300- 440
Mining	220- 290	440- 580
Processed shale disposal	2,480-4,230	4,960- 8,460
Retorting	580- 730	1,160- 1,460
Refining	1,460-1,820	2,920- 3,640
Other uses 3/	70- 440	80- 580
TOTAL	4,960-7,730	9,860-15,160
Water Available from:		
Retorting	170- 360	340- 730
Refining	110	220
Mine development 4/	7,880	12,410
Other 5/	100	200
TOTAL	8,260-8,450	13,170-13,560
Water Balance		
High quality water requirements 6/	2,110-2,990	4,160- 5,680
High quality water from mine 7/	3,960	6,205
EXCESS HIGH QUALITY	1,830- 950	2,045- 525
Poor quality water requirements 8/	2,850-4,740	5,700- 9,480
Poor quality water from mine and processing 9/	4,320-4,510	6,965- 7,365
EXCESS POOR QUALITY	1,660-(-)420	1,665-(-)2,515
Trial Water Balance:		
Excess high quality	1,830- 950	2,045- 525
Excess poor quality	1,660-(-)420	1,665-(-)2,515
SURPLUS 10/ or DIVERSION (-) 11/	3,490- 530	3,700-(-)1,990

1/ 50,000 barrels per day

2/ 100,000 barrels per day

3/ Primarily net domestic consumption for associated population

4/ Average produced water over 30-year period (3)

5/ Other sources, such as boiler blowdown, bleed-off from cooling water, etc.

6/ Requirement for retorting, refining, and other uses such as drinking and sanitation purposes.

7/ Assumes half of the produced water from the mine is of high quality

8/ Requirement for crushing, mining, and spent shale disposal

9/ Processes include retorting and refining

10/ Surplus poor quality water would require desalting, evaporation in impermeable ponds, or disposal by subsurface injection

11/ Diverted water would be from surface water in the Colorado River system.

FIGURE D-6. TRIAL WATER BALANCE FOR TWO HYPOTHETICAL MINE DEVELOPMENTS IN COLORADO

Source: Reference D-1.

diagrams of these balances are shown in Figure D-7 for an underground mine and in Figure D-8 for a surface mine. Table D-2 shows the water balance as a function of pumped mine water quality.(D-1)

TABLE D-2. WATER BALANCE AS A FUNCTION OF PUMPED MINE WATER QUALITY, ACRE-FEET/YEAR(a)

	Underground Mine			Surface Mine		
High-quality mine water, percent of total	0	50	100	0	50	100
Excess water of poor quality	3,520 to 5,600	(-) 240 to 1,660	0	3,690 to 7,860	(-)2,515 to 1,655	0
Excess water of high quality	0	950 to 1,830	530 to 3,490	0	525 to 2,045	3,700 to (-)1,900
Surplus or diversion (-)	5,600 to (-)2,990	530 to 3,490	530 to 3,490	7,860 to (-)5,680	3,700 to (-)1,990	3,700 to (-)1,990

(a) See Table D-1 for derivation of 50 percent columns.

Examination of these data shows the wide range of possibilities, depending on the actual flow encountered, aquifer characteristics of the region, and quality of the water produced. Some of the major potential emissions are listed as follows:

- Lowering of Water Tables in Vicinity of the Mine. Lowering of watering tables in the vicinity of the mine could lead to drying up of springs and diversion from surface stream flows in the vicinity resulting in increased mine waters and some interference with existing water rights. In some areas where nahcolite deposits are present, leaching could occur leading to subsidence of the land surface and a substantial increase in water salinity.

- Increasing Mine Depth Over Time. As mining operations proceed, the likelihood of encountering higher saline waters would increase, reducing the overall water quality. Should the amounts encountered exceed operational needs for poor quality water, problems in disposal could become severe.

- Erosion and Leaching of Spent Shale Deposits. As mentioned earlier, erosion and leaching of the spent shale deposits can create a major

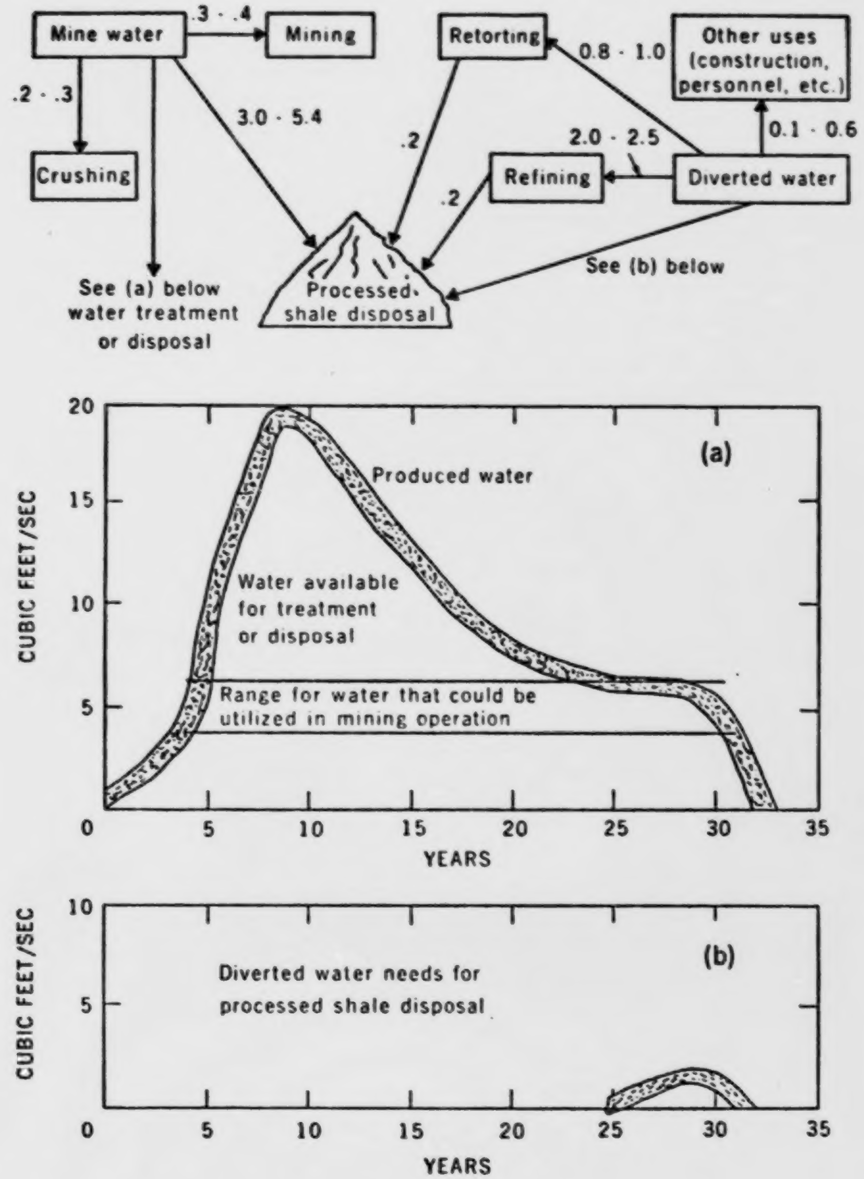


FIGURE D-7. WATER SUPPLY AND DEMAND IN CU FT/SEC FOR UNDERGROUND MINE, 50,000 BBL/DAY OF SHALE OIL

Source: Reference D-1.

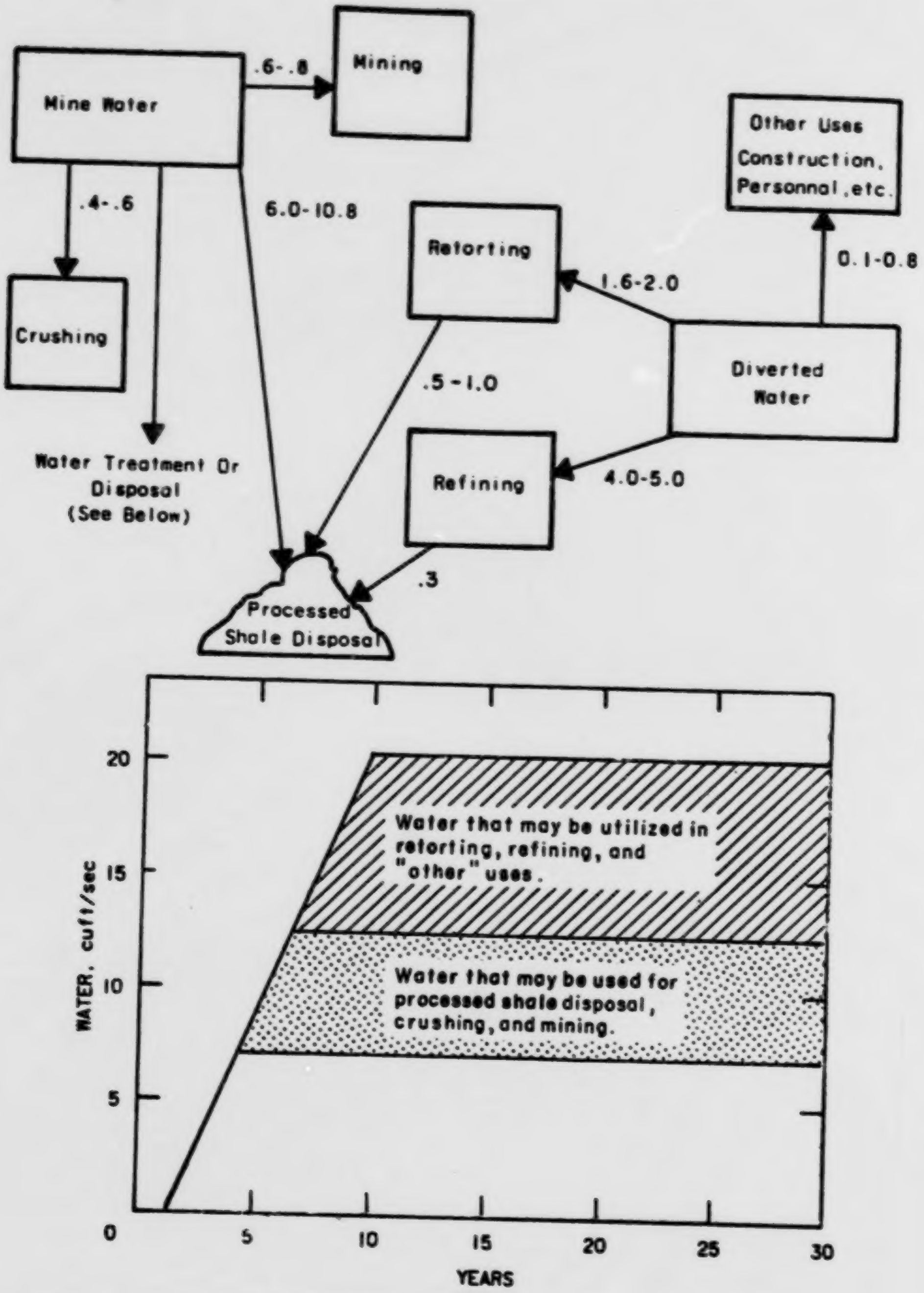

Mine Water
.6-.8
Mining
.4-.6
6.0-10.8
Crushing
Water Treatment Or
Disposal
(See Below)
Retorting
.5-1.0
Refining
.3
Processed
Shale Disposal
1.6-2.0
4.0-5.0
Diverted
Water
0.1-0.8
Other Uses
Construction,
Personnal, etc.
Water that may be utilized in retorting, refining, and "other" uses.
Water that may be used for processed shale disposal, crushing, and mining.
WATER, cuft/sec
20
15
10
5
0
5
10
15
20
25
30
YEARS

FIGURE D-8. WATER SUPPLY AND DEMAND CU FT/SEC FOR SURFACE MINE 100,000 BBL/DAY

Source: Reference D-1.

pollution problem unless adequate controls are established. Recent experimental studies conducted at Colorado State University(D-4) suggest that the presence of snow may create a greater leaching problem than rainfall because of the longer contact time. Channeling of water flow away from canyons containing spent shale and collection of surface runoff in downstream ponds is recommended. Other recommendations include wetting and compaction of the spent shale piles and avoiding direct exposure of the top surface of the shale piles to the elements to the extent possible.

Spent shale deposited in underground mines would also be subject to leaching if the mine workings were flooded while active or after mining operations ceased. The possible effect of this is unknown at this time.

- Domestic Wastes. The U.S. Department of Interior has estimated that a 400,000 barrel-per-day operation would require a population increase of about 47,000 people in the region. Extrapolation of this requirement to a 1,000,000 barrel-per-day operation would indicate a population increase of about 117,500. Population of the region in 1970 was about 119,000, so domestic demands for water would essentially double present requirements. Some degradation of water quality would probably occur, the extent of which would be determined by the type and extent of municipal water treatment systems that might be installed.

- Water Consumption. The net water consumed for various rates of shale oil production is shown in Table D-3. If all of this water obtained either directly or indirectly from surface and ground waters that would otherwise contribute to the flow of the Colorado River, the salinity at Hoover Dam would be expected to increase between 6 and 10 mg/l, or an increase in salinity of about 1.4 percent. This might be considered the worst normal case if supply of water is less than demand. On the other hand, if supply of water is greater than demand, an average salinity of the effluent above about 740 mg/l would add to the salinity content at Hoover Dam. This indicates the desirability of the construction of different holding basins, maximum utilization of high saline-content water where possible, and the prevention of inadvertent discharge of high-saline content water.

- Operational Spills. The possibility always exists for accidental spills of oils and chemicals in process operations. The establishment of controls similar to best technology used in petroleum refining should minimize potential water contamination from these sources.

Little information is available regarding impact on water quality that might result from in-situ operations. Dewatering of the in-situ site would be required involving some means of disposing of this water. Methods used would depend on its salinity. There also would be potential contamination of ground water supplies, subsequent to the underground fracturing, retorting, and recovery of the shale oil. Further experimentation will be needed to determine the severity of the problem

TABLE D-3. WATER CONSUMED FOR VARIOUS RATES OF SHALE OIL PRODUCTION

Function	Shale Oil Production - barrels per day Net Water Consumed, acre feet per year 50,000	 100,000	 250,000	 1,000,000[(a)]
Mining	220 - 290	440 - 580	1,100 - 2,900	3,500 - 6,100
Crushing (dust control)	150 - 220	300 - 440	800 - 1,100	2,400 - 3,500
Retorting	580 - 730	1,160 - 1,460	2,900 - 3,700	9,300 - 11,700
Processed Shale Disposal	2,480 - 4,230	4,960 - 8,460	12,400 - 21,200	39,700 - 67,700
Shale Oil Upgrading	1,460 - 1,820	2,920 - 3,640	7,300 - 9,100	23,400 - 29,100
Other[(b)]	70 - 440	80 - 580	400 - 2,300	1,000 - 6,300
TOTAL	4,960 - 7,730	9.860 -15,160	24,900 - 40,300	79,300 - 124,400

(a) This million barrel per day production is assumed to be derived from 5 underground, 1 surface, and 1 in-situ operation.

(b) Primarily net domestic consumption for associated population.

Source: Reference D-4.

involved in any specific location. Underground migration of the shale oil and gases produced by the combustion process also might be a major source of water pollution in the area. Treatment methods also would have to be established for the water produced in conjunction with the shale oil and gases to maintain desired water quality.

Impact on Fish and Wildlife

Noise levels would be substantially increased because of blasting, earth moving equipment, crushing and grinding operations, compressors, pumps, processing operations, etc., involved in this massive industrial operation. This and other factors associated with industrial development would change the character of the region and would have a significant impact on the wildlife presently inhabiting the area. Some species, such as mountain lions, elk, and peregrine and prairie falcon would be intolerant. Others would be affected to a lesser degree.

The impact on fish and other aquatic life would depend on the extent and frequency of water pollution that may occur--over time.

Impact on Aesthetics, Recreation, and Cultural Values

Presently, the area is remote and sparsely settled. Average population density is about three persons per square mile. Recreation activities involve hunting, fishing, and boating, by both residents and tourists. Within the 25,000-mile region there are a wide variety of unique features and scenic wonders. Historic areas are primarily associated with Indian culture. The development of a large-scale oil-shale industry would create many irreversible changes. With proper location of mining and processing operations, the major aesthetic values and historical sites can be maintained, but the substantial increases in residents and in visitors (both business and vacationers) would expand recreational utilization of the region while at the same time fish and wildlife population might be expected to decline.

Economic Considerations

Costs that may be involved in the development of a major shale oil industry are subject to a wide variation, depending on the type and location of operations that may be established.

An appraisal made by the Oil Shale Task Group of the National Petroleum Council in 1971 provided estimates of capital and operating costs that might be involved in 12 cases involving four mining methods and three grades of oil shale. These estimates are shown in Table D-4.(D-5) This table shows capital costs ranging from $522.6 million to $746.6 million including the required construction period for each mining method evaluated and a 20-year operating period, including a three-

TABLE D-4. ESTIMATED COSTS FOR PRODUCING 100,000 BBL/CD SYNCRUDE FROM OIL SHALE (AT MID-YEAR 1970)

	25 GAL/TON SHALE				30 GAL/TON SHALE				35 GAL/TON SHALE			
OIL SHALE MINED & RETORTED, TONS/CD	174,800				145,600				124,800			
CRUDE SHALE OIL PRODUCED, BBL/CD	104,000				104,000				104,000			
MINING METHOD	SURFACE		UNDERGROUND		SURFACE		UNDERGROUND		SURFACE		UNDERGROUND	
	PIT	STRIP	ADIT	SHAFT	PIT	STRIP	ADIT	SHAFT	PIT	STRIP	ADIT	SHAFT
CAPITAL, $ MILLION												
MINING, CRUSHING, ASH DISPOSAL												
INITIAL	176.8	95.4	105.0	130.8	147.2	79.4	87.6	109.0	126.2	68.2	75.0	93.4
DEFERRED	94.2	79.4	71.4	74.0	78.4	66.0	59.4	61.6	67.2	56.6	51.0	52.8
RETORTING	248.2	248.2	248.2	248.2	206.8	206.8	206.8	206.8	177.2	177.2	177.2	177.2
UPGRADING	192.8	192.8	192.8	192.8	192.8	192.8	192.8	192.8	192.8	192.8	192.8	192.8
WATER SYSTEM	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
TOTAL INVESTMENT	719.0	622.8	624.4	652.8	632.2	552.0	553.6	577.2	570.4	501.8	503.0	523.2
WORKING CAPITAL	27.6	27.6	27.6	28.8	23.6	23.6	23.6	24.8	20.8	20.8	20.8	21.8
TOTAL CAPITAL (NOT INCL. LAND)	746.6	650.4	652.0	681.6	655.8	575.6	577.2	602.0	591.2	522.6	523.8	545.0
OPERATING COSTS, $ MILLION/YEAR (NOT INCLUDING DEPRECIATION)												
MINING, CRUSHING, ASH DISPOSAL	39.6	39.6	39.6	42.8	33.0	33.0	33.0	35.6	28.2	28.2	28.2	30.6
RETORTING	20.4/25.6				17.0/21.2				14.6/18.2			
UPGRADING	16.8/19.4				16.8/19.4				16.8/19.4			
WATER SYSTEM	0.4				0.4				0.4			
TOTAL OPERATING COSTS												
FIRST 15 YEARS	77.2	77.2	77.2	80.4	67.2	67.2	67.2	69.8	60.0	60.0	60.0	62.4
AFTER 15 YEARS	85.0	85.0	85.0	88.2	74.0	74.0	74.0	76.6	66.2	66.2	66.2	68.6

UNIT COSTS

	MINING, CRUSHING, AND ASH DISPOSAL				RETORTING OIL SHALE	UPGRADING CRUDE SHALE OIL	
	PIT	STRIP	ADIT	SHAFT			
CAPITAL ($ PER TON/CD)--INITIAL	1011	546	601	748	1420	($ PER BBL/CD)	1854
DEFERRED	539	454	409	424	--		--
OPERATING COST (¢ PER TON)						(¢ PER BBL)	
FIRST 15 YEARS	62	62	62	67	32		44
AFTER 15 YEARS	62	62	62	67	40		51

NPC ENERGY OUTLOOK

Source: Reference D-5.

month start-up period during the first year of operation. Deferred costs for replacement of equipment and working capital requirements are included.

The effect of differences in mining method and shale quality on discounted cash flow rates of return for various syncrude value is shown in Table D-5. The same type information for the four mining methods is shown in Figures D-9 to D-12. These figures illustrate the sensitivity of mining method and shale quality on the value of syncrude needed to secure the same rate of return. For example, to secure a 15 percent rate of return on shale assaying 25 gallons per ton in open pit mining would require a syncrude value of $6.65 per barrel compared with about $6.08 for strip mining, $6.12 for adit mining, and $6.40 for shaft mining. On the other hand, utilizing a shale assaying 35 gallons per ton would reduce the necessary syncrude value to $5.30 per barrel for open pit mining, $4.90 for strip mining, $4.92 for adit mining, and $5.10 for shaft mining. All of these estimates include a 25 percent contingency in the retorting and upgrading investments. In comparison, the U.S. Department of Interior estimates of capital and operating costs, as presented in their recent study,(D-1) are shown in Table D-6 for underground, open pit, and in-situ operations. It should be noted that both capital and operating cost estimates are appreciably lower than those prepared by the National Petroleum Council.

In addition to the direct costs involved in developing a million barrel per day oil shale industry, substantial investments would be required in the infrastructure needed to support the operation. As mentioned earlier, a population increase of more than 100,000 would be required. Assuming an average capital cost of about $12,000 per individual for the required housing, commercial and community facilities would indicate a requirement of about $1.2 billions of dollars.

Economic Costs for Environmental Protection

The cost estimates prepared by the National Petroleum Council and the U.S. Department of Interior both include estimated costs of providing environmental safeguards and facilities designed to meet present environmental standards. However, prior to the actual selection of specific locations and methods of operation, it is impossible to determine the costs that might be involved in providing the necessary environmental safeguards. Furthermore, actual operating conditions encountered might require substantial changes in presently envisioned means of providing the needed environmental protection.

The vast bulk of economic costs required for environmental protection will be concerned with mining operations and disposal of the spent shale and overburden. More than a third of the capital costs and about half of the operating costs will be involved in these operations. Costs involved in disposal methods may account for up to 50 percent of these requirements, and substantial portion of this total would be for prevention of leaching and erosion from spent shale and overburden

TABLE D-5. EFFECT OF MINING METHOD AND SHALE QUALITY ON SYNCRUDE VALUE

Mining Method	Shale Assay gal/ton	Discounted Cash Flow Rate of Return, % for Indicated Syncrude Value in $/bbl					
		4.00	4.50	5.00	5.50	6.00	6.50
SURFACE							
Open pit	25	5.6	7.8	9.7	11.4	13.0	14.5
	30	8.1	10.2	12.0	13.8	15.4	17.0
	35	10.0	12.0	13.9	15.7	17.4	19.0
Strip	25	7.0	9.2	11.2	13.0	14.7	16.4
	30	9.4	11.6	13.6	15.4	17.2	18.9
	35	11.2	13.4	15.4	17.4	19.2	21.0
UNDERGROUND							
Adit	25	6.9	9.1	11.1	12.9	14.6	16.2
	30	9.3	11.5	13.4	15.3	17.0	18.7
	35	11.1	13.2	15.3	17.2	19.1	20.8
Shaft	25	6.1	8.3	10.3	12.1	13.8	15.3
	30	8.6	10.7	12.7	14.5	16.2	17.9
	35	10.4	12.6	14.6	16.4	18.2	19.9

Source: Reference D-5.

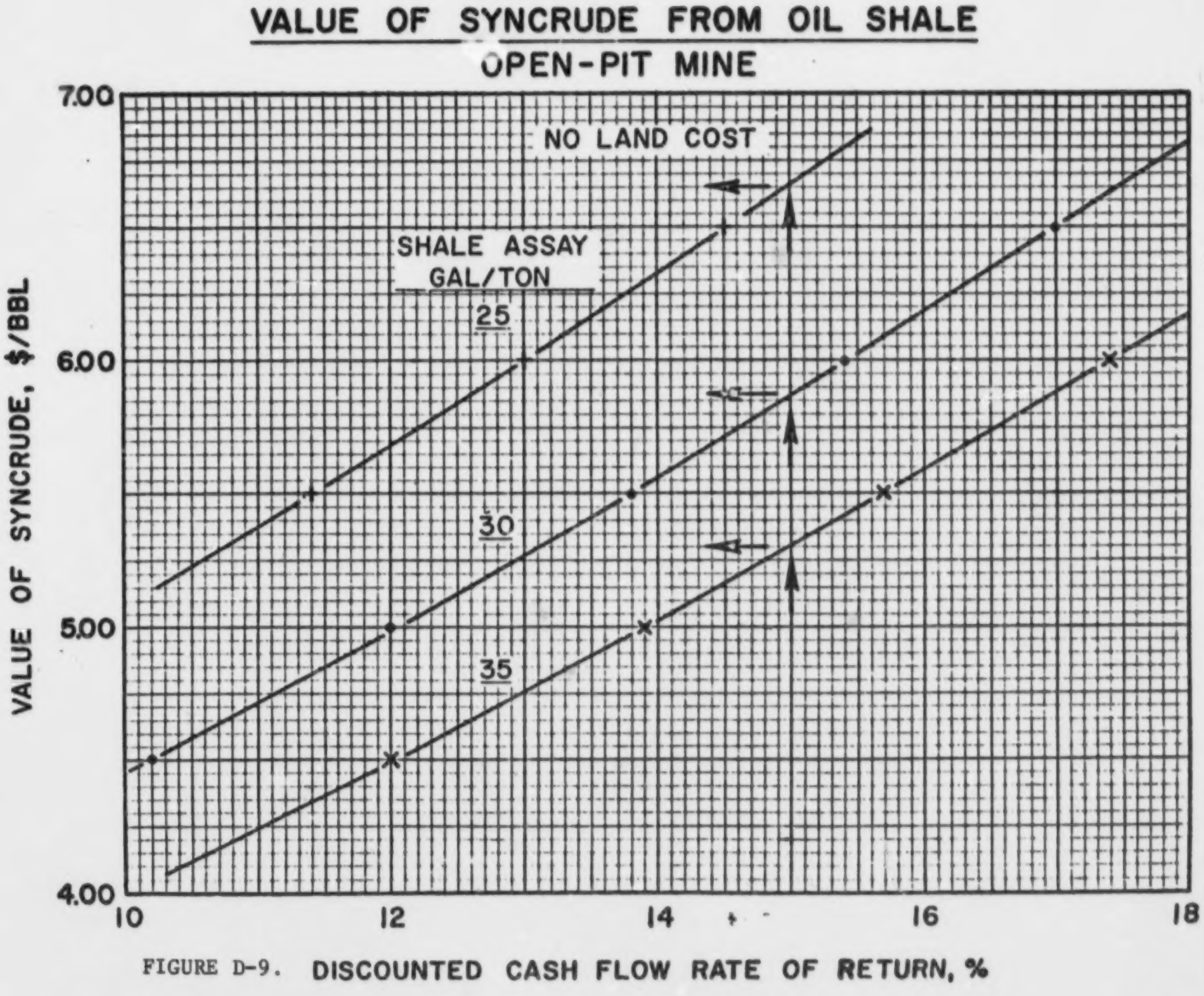

VALUE OF SYNCRUDE FROM OIL SHALE
OPEN-PIT MINE
NO LAND COST
SHALE ASSAY
GAL/TON
25
30
35
VALUE OF SYNCRUDE, $/BBL
7.00
6.00
5.00
4.00
10
12
14
16
18
DISCOUNTED CASH FLOW RATE OF RETURN, %

FIGURE D-9.

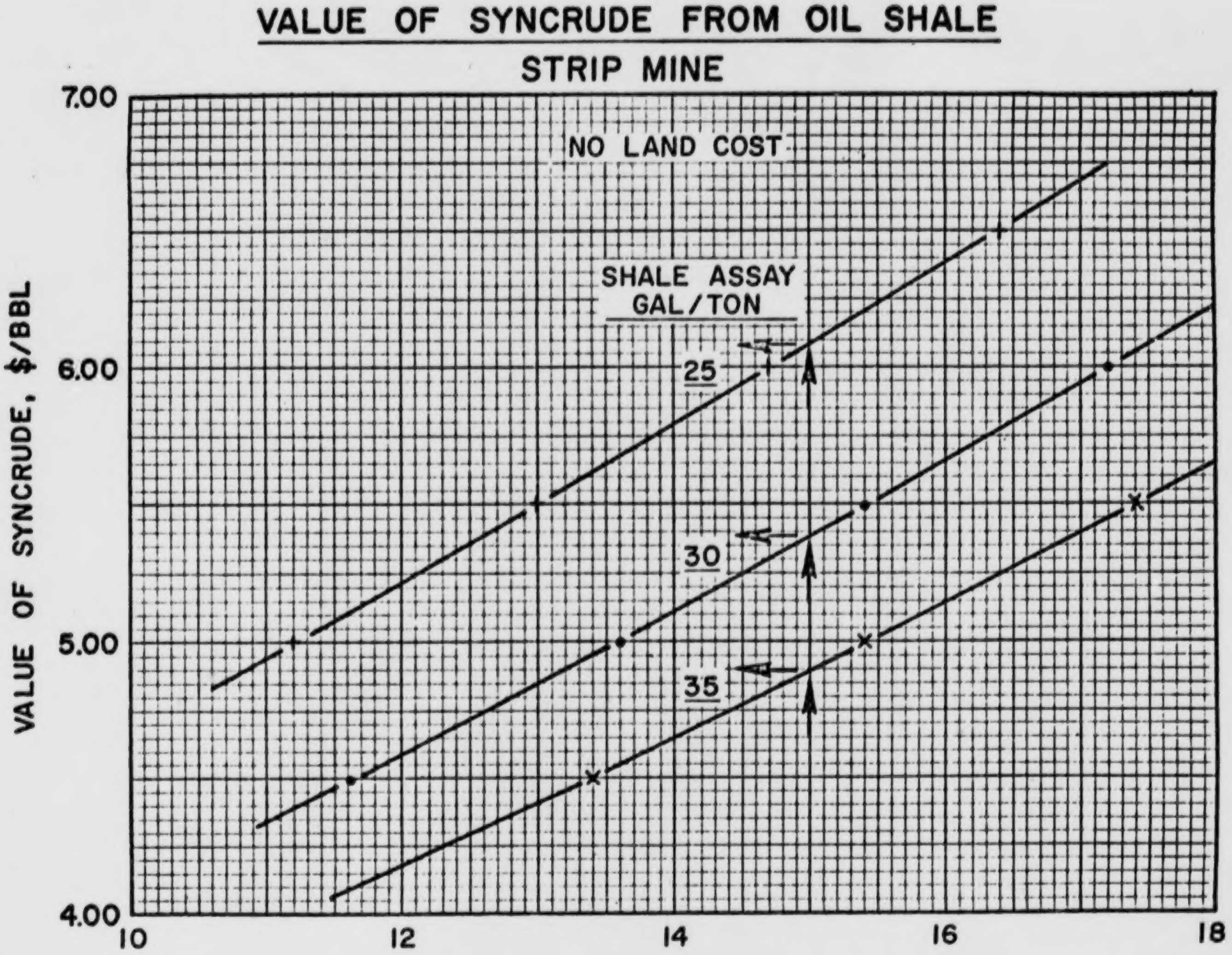

VALUE OF SYNCRUDE FROM OIL SHALE
STRIP MINE
NO LAND COST
SHALE ASSAY GAL/TON
25
30
35
7.00
6.00
5.00
4.00
VALUE OF SYNCRUDE, $/BBL
10
12
14
16
18
DISCOUNTED CASH FLOW RATE OF RETURN, %

FIGURE D-10.

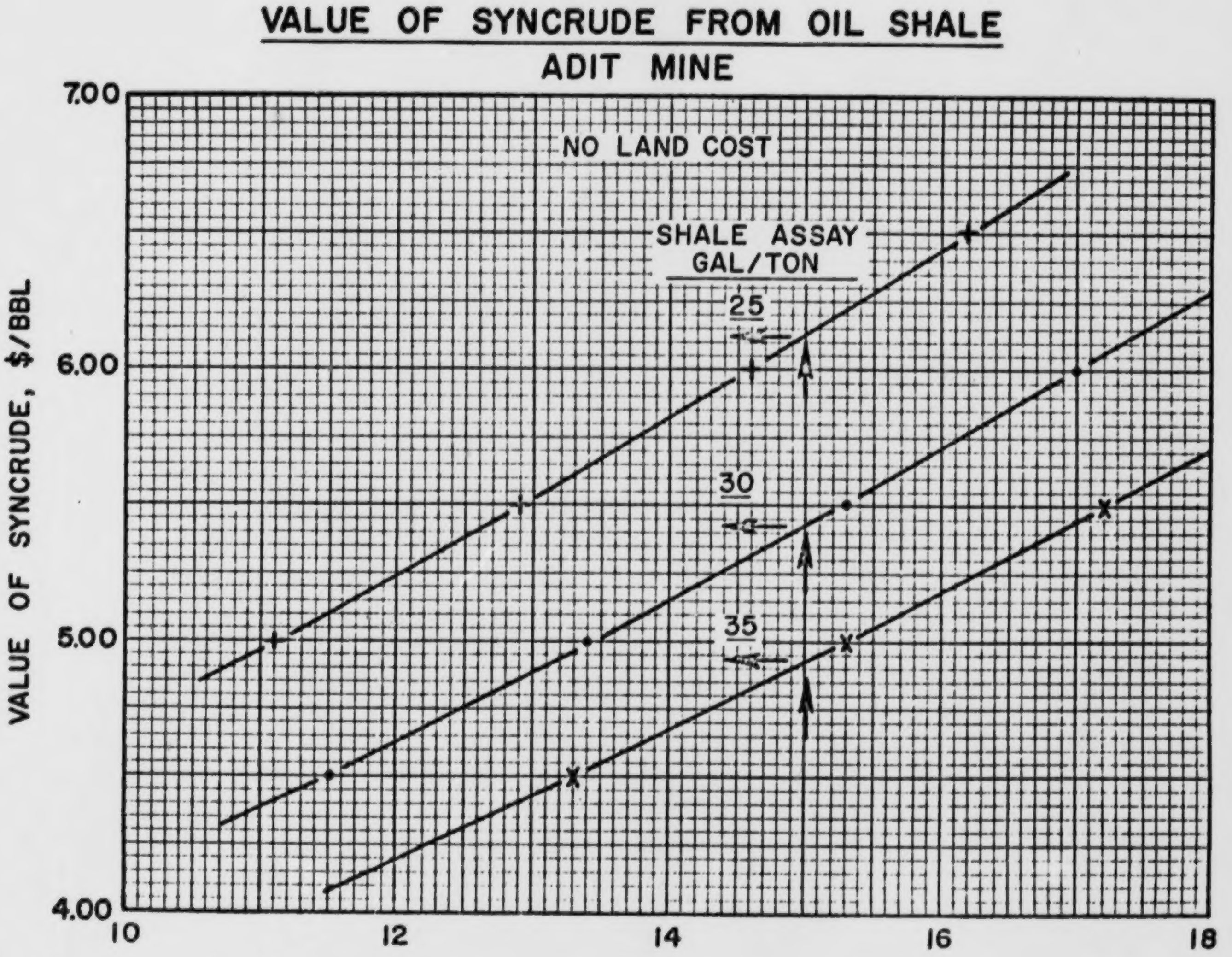


FIGURE D-11.
Source: Reference D-5.

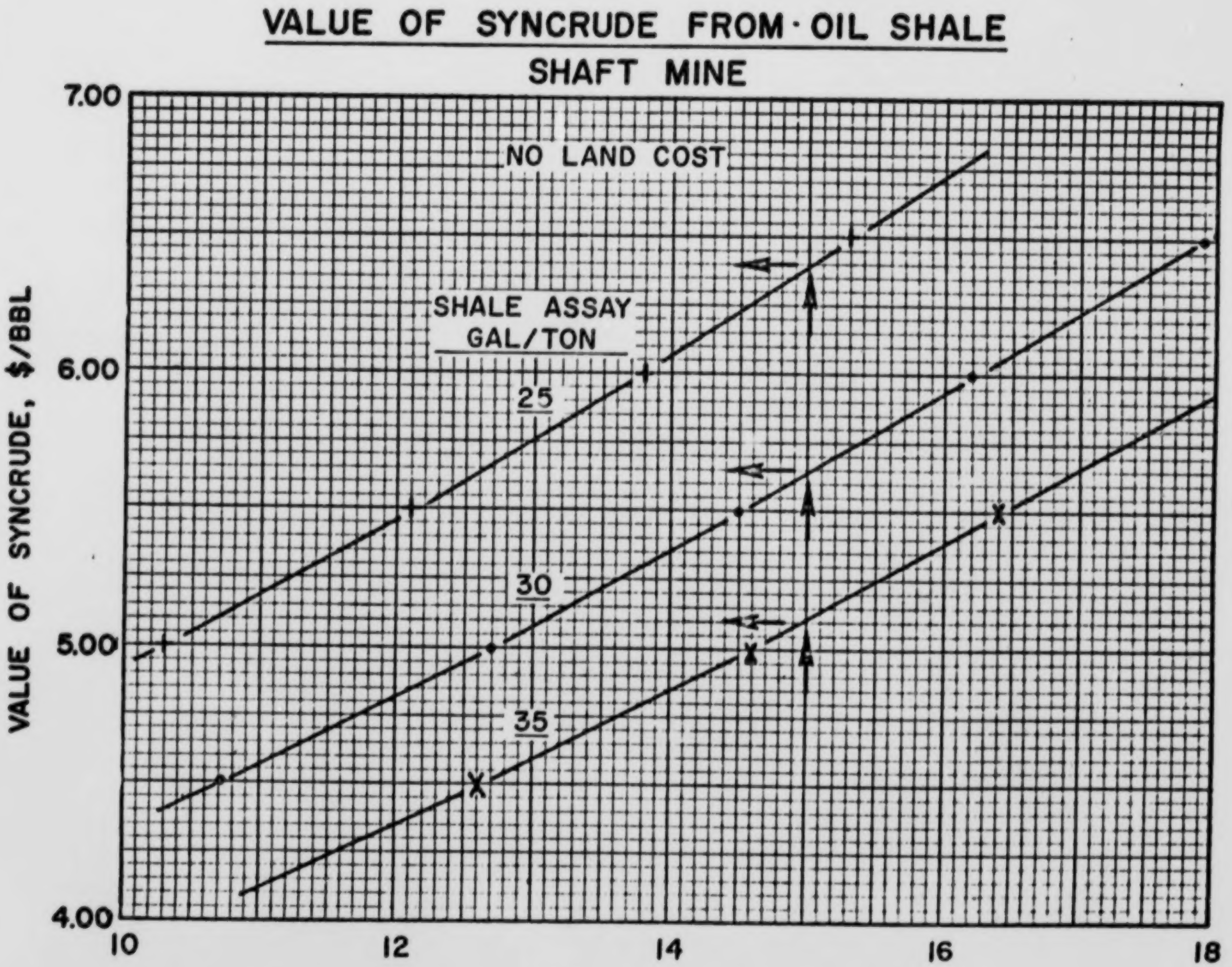


FIGURE D-12. DISCOUNTED CASH FLOW RATE OF RETURN, %

TABLE D-6. OIL SHALE CAPITAL AND OPERATING COSTS

(Millions of Dollars)

Mining Option	Plant Capacity,[a] 50	Thousand bbl/day 100
Underground with Mine Disposal		
Capital costs:		
Labor	35.2	
Equipment	187.2	
TOTAL	222.4	
Annual operating costs:		
Labor	11.2	
Supplies	14.9	
TOTAL	26.1	
Open Pit with Backfill		
Capital costs:		
Labor		51.2
Equipment		267.8
TOTAL		319.0
Annual operating costs:		
Labor		15.8
Supplies		17.9
TOTAL		33.7
In Situ (non-nuclear fracturing)		
Capital costs:		
Labor	19.8	---
Equipment	213.9	---
TOTAL	233.7	---
Annual operating costs:		
Labor	13.1	---
Supplies	2.1	---
TOTAL	15.8	---

(a) Except for in situ, capacity is based on Bureau of Mines gas combustion retort and is in terms of semirefined shale oil and 1970 dollars.

and for restoration of the land surface to minimize degradation of aesthetic values. Thus, costs may be in the range of \$0.50 to \$1.00 per ton of material, or upwards of \$0.70 per barrel of shale oil produced.

Economic costs involved in retorting and upgrading operations would be similar to those encountered in petroleum refining.

References

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APPENDIX E

COAL MINING AND UNDERGROUND GASIFICATION OF COAL

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APPENDIX E

COAL MINING AND UNDERGROUND GASIFICATION OF COAL

Coal Mining

To benefit the economy through the use of coal for steam raising, electric power generation, carbonization, and gasification (the important applications), coal must be recovered from beneath the surface of the earth, by either underground or stripping systems involving the removal of varying thicknesses of overburden to reveal the seam. The only alternative to such mining systems is underground gasification, which is treated in the second section of this appendix.

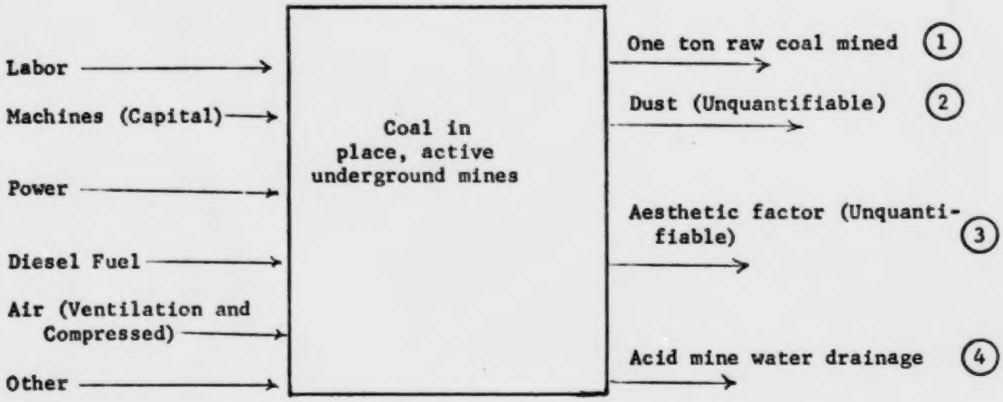
A number of different physical systems are used underground to mine coal, depending on geological conditions. In any event, to mine coal underground requires inputs of electric power, diesel fuel, water, compressed air, explosives, ventilating air, rock dust, and other physical components, in addition to men (labor) and machines (capital). The product is coal, and the by-products are (1) mineral materials (usually partially removed in associated coal-cleaning plants), (2) some coal dust (which results from handling at the surface, but is a local, minor factor), and (3) acid mine drainage, which represents the principal environmental problem of the underground coal mining operation. An additional problem of underground coal mining is the aesthetic factor, which, however, is of greater significance in the refuse piles of cleaning plants and the unreclaimed surface mining operations.

In surface mining operations there is the input of labor (less intensive than underground mining), machines, power, ancillary materials and supplies, and the environmental factors, attendant on the production of coal, principally due to aesthetic values and acid mine drainage.

The Underground Coal Mining Module

Figure E-1 represents a module for the input-output factors for the recovery of a basic unit of one ton of coal by underground mining. As mentioned previously, the chief inputs are labor, supplies, power, and machines, while the output in addition to the product coal, are acid mine drainage and local dust.

An Attempt to Quantify the Acid Mine Drainage for the Appalachian Bituminous Coal Mining Region, Active Mines. Recently, Tybout(E-1) has estimated costs of alleviating acid mine drainage on the basis of studies made in Pennsylvania by the Pennsylvania Department of Mines and Mineral Industries and the Pennsylvania Department of Health with


Labor
Machines (Capital)
Power
Diesel Fuel
Air (Ventilation and Compressed)
Other
Coal in place, active underground mines
One ton raw coal mined ①
Dust (Unquantifiable) ②
Aesthetic factor (Unquantifiable) ③
Acid mine water drainage ④

① One ton of coal brought to the surface represents about 50 percent of the coal in place in the seam, on the average. Some mining situations are better, some slightly worse. A refinement would translate the unit ton into a basic one million Btu (or multiple).

② Some dust is produced from handling the mined coal brought to the surface whether it is loaded for transport or delivered to a cleaning plant. The amount is of local significance and not quantifiable.

③ The aesthetic factor is not quantifiable.

④ The acid mine water produced by a given mining situation may be approximately determined and measures taken to minimize the problem. The pyrite in the coal remaining in the mine, in the roof, floor, pillars, partings, etc. represents the raw material contributing to the production of acid mine waters through the processes of oxidation of the pyrite, leaching of the acidic product and removal from the area by ground water in natural flow or by pumping.

FIGURE E-1. REPRESENTATION OF COAL MINING MODULE respect to the volume of drainage. On the basis of that report, the average volume of acid mine drainage from active bituminous coal mines in Pennsylvania is assumed to be 7.15 gallons per square foot of mine roof exposed per year. A further assumption is made that this average figure for mine drainage volumes in Pennsylvania can be extended to represent the whole of the Appalachian region. In the absence of similar data for the same type of coal mining in these other states--no averaged data could be found--this assumption must be used as a first approximation.

It should be noted that the quantity of acid mine waters produced by an active bituminous mining operation depends, among other factors, on the number of years the mine has been operated. This results from the fact that the amount of oxidation of the pyrite (and the amount of the oxidized products that can be removed by leaching and solution in the water present) is controlled by the area of surface exposed. Thus, the quantity of acid mine water released by a given mine is a factor of the age of the mine. Presumably, in the collection of data on volume of acid mine water produced, the average value represents the mine age factor.

To translate the average volume of acid mine drainage per year per square foot of roof area to a more descriptive unit basis, average values for the density of the coal in place, and the thickness of the seam are required. This entails the assumption that the area of roof exposed is proportional to the amount of coal produced and to the resulting volume of mine drainage.

The average density of the bituminous coal in place in the Appalachian area is assumed to be 82.6 pounds per cubic foot.(E-2)

The average thickness of the coal seams of active mines in the states of the Appalachian region is assumed to be 4.9 feet. This was derived from Bureau of Mines collected data for the year 1965,(E-3) together with production data for the year 1970.(E-4) From these data a weighted average value for bituminous coal seam thickness as of 1970 was obtained. Use of 1965 coal seam thickness data with 1970 coal production figures is justified by the fact that the average seam thickness (all bituminous and lignite underground mines) in the United States was 5.3 feet in 1945, 5.4 feet in 1950, 5.3 feet in 1955, 5.4 feet in 1960, and 5.3 feet in 1965. In the Appalachian coal mining region the average seam thickness in 1965 for bituminous coal production varied from extremes of 3.6 feet in Maryland to 5.3 feet in Pennsylvania.

The calculated averaged output of acid mine water per ton of coal produced in 1970 in the Appalachian bituminous coal mining region is calculated to be:

$$\frac{\overset{\text{gallons/sq ft}}{\overset{\searrow}{71.5}} \times \overset{\text{pounds/ton}}{\overset{\swarrow}{2000}}}{\underset{\underset{\text{pounds/ft}}{\nearrow}}{82.6} \times \underset{\underset{\text{feet (thickness)}}{\nwarrow}}{4.9}} = 353 \text{ gallons per ton of coal mined}$$

Since the number of tons of bituminous coal mined in the Appalachian states in 1970 totaled 294.2 million tons, the total volume of acid mine water produced, under the assumptions stated, was 103.8 billion gallons during 1970. The average acidity of the produced mine water is not known. In evaluating acid mine drainage abatement costs,(E-2) the quality of the drainage water was assumed to be weakly acidic (i.e., ≈ 500 mg per liter as $CaCO_3$) with 1600 ppm TDS.

Acid Mine Drainage in Other Bituminous Coal Mining Areas (Underground). Mining conditions (underground) in the flatter terrain of the central bituminous coal mining states are somewhat different than in the Appalachian area. Accordingly, the assumed value for the average volume of acid mine water produced per unit roof area exposed may not be the same. During the short period of time allowed for search for pertinent values, none representing average values was found. Further study would be required to determine a reasonably satisfactory value.

The same is true for the western bituminous coal mining states with appreciable underground operations, such as Colorado and Utah.

Surface Coal Mining

In 1970, almost 600 million tons of bituminous coal and lignite were mined in the United States. Approximately 46 percent of the coal was produced from mines located in Ohio, Pennsylvania, and West Virginia. Of the total production, about 56 percent was from underground coal mines. Approximately 41 percent of the total was produced in strip mines, and the balance--slightly more than 3 percent-- by auger mining techniques.(E-5)

The 1960 decade saw the total production of bituminous coal and lignite by strip mining techniques about double, from about 120 million tons to about 240 million tons or from about 30 percent to 41 percent of the total annual production. These data indicate the increasing importance of surface mining techniques in the production of coal and the importance of minimizing the environmental effects of surface mining.

Although surface mining techniques are complex operations, they consist basically of removing the topsoil, rock, and other materials above the coal seam so that the coal can be recovered. Surface mining of coal embraces three general techniques:(E-6)

1. Area strip mining

2. Contour stripping

3. Auger mining

Area strip mining is used where the terrain is relatively flat. It consists of cutting a trench through the overburden to expose a portion of the coal seam. After the exposed coal has been removed, a parallel cut is made with the overburden from the new cut being deposited in the void left by the previous cut. The final cut leaves an open void bounded on one side by the highwall and on the other by the last spoil bank. The overall surface effect on the unreclaimed land has been described as the creation of a gigantic "washboard". This effect can be eliminated by proper grading and leveling.

Contour stripping is used in rolling or mountainous terrain. This technique consists of removing the overburden--starting at the outcropping of the coal seam--and proceeding along the hillside. After the first cut is made and the coal is removed, additional cuts are made until the ratio of recovered coal to overburden becomes so small that the operation no longer is economically feasible. Contour strip mining of coal creates a "bench" on the hillside bordered on one side by the highwall and on the other by a sharp grade covered by spoil. This can result in landslide and severe erosion unless it is controlled.

The quantities of coal produced by these two techniques--area strip mining and contour stripping--were about equal in 1970. The latter technique is practiced extensively in the Appalachian area.

Auger mining usually is associated with contour stripping. The technique is used to recover the coal which can no longer be mined economically by contour stripping. It also is used to recover coal from outcroppings which can't be mined safely by underground techniques.

Among the adverse environmental effects of surface mining of coal are (E-2)

1. Destruction of the vegetative covering

2. Creation of massive piles of spoils

3. Drastic reshaping of the terrain

4. Sliding of spoils and blockage of streams

5. Pollution of streams with sulfuric acid and silt

6. Destruction of economic and esthetic value of the land.

By 1965, more than 1.3 million acres of land had been disturbed by the surface mining of coal. The annual rate of increase in the area of land disturbed by these activities amounted to over 46,000 acres in 1964. The increasing demand for coal coupled with the increased use of surface mining techniques makes the development of improved techniques for controlling the pollution of all environmental media by these activities imperative.

Surface mining of coal is not a major contribution to the overall problem of air pollution. However, the burning of fuels in mining and hauling equipment, the dust and other materials emitted during blasting operations, and airborne dust from active and abandoned mines as well as from spoils piles do contribute to air pollution.

Surface mining of coal contributes to the pollution of streams and underground water supplies. Significant pollutants include sulfuric acid, and iron; trace metals such as arsenic, copper, lead, manganese, and zinc; and silt. In the Appalachian region it has been estimated that the siltation from surface mined areas may be 1,000 times that from undisturbed terrain.

Both the air and water pollution problems created by the surface mining of coal are increased significantly by improper reclamation of the land area which has been disturbed by the mining operations. Often restoration of the land to its original vegetation is difficult because of the physical and chemical nature of the solid waste produced during the stripping operations. The quantity of such waste produced per ton of coal recovered vary greatly from deposit to deposit as well as amount within a given deposit. In the Appalachian area an average of about 33 tons of solid wastes are produced per ton of coal mined.(E-7) The solid wastes produced in Western surface mines average about 17 tons per ton of coal produced.(E-7)

Methods of land restoration are described in the following sections of the Appendix. Current costs for such restoration have been estimated at $500 to $2,000 per acre, with $1,000 per acre being a reasonable average.

Land Restoration. There are currently no Federal regulations regarding land restoration following strip mining. The more stringent state regulations are designed to assure the environmental acceptability of the operation. Such regulations include the following practices.(E-8)

1. Removal of top soil for redistribution after the operation

2. Backfilling so as to bury pyritic material or other material which will not support life.

3. For "area" stripping, grading to the original contour over which farm machines can travel

4. For "contour" stripping, reduction of the high wall is required

5. Replanting a ground cover. Generally, 70 to 80 percent ground cover with no more than 1/4 acre bare, to include 600 living stems (shrubs and trees) per acre, is required. Survival checks are usually made during two growing seasons.

Assuming this type of land restoration the environmental emissions will become negligible after the restoration is complete. It is assumed that the miming operation will require 1 year and that 2 years are required to stabilize the land.(E-8)

Treatment of Mine Drainage. Treatment of mine drainage refers predominantly to treatment of waters containing varying amounts of ferrous sulfate, ferric sulfate, aluminum sulfate, magnesium sulfate, manganese sulfate, and very small amounts of free sulfuric acid. Often a partial neutralization has taken place via the natural calciferous materials present and thus calcium sulfate is often present. In some cases, the iron is originally present as the bicarbonate salt and thus the waters are neutral, but still highly mineralized. Little sulfate is normally present in this latter instance.

Methods of removing these metal salts, or neutralizing the acidic salts are known. Neutralization is the best known and the one which has the most actual practice. Other physical separations methods such as reverse osmosis, ion exchange, freezing, and electrodialysis have been studied. Freezing has been found to be expensive and relatively ineffective. Electrodialysis is poisoned by the iron present in the feed waters and thus is technically not feasible. Reverse osmosis has been extensively studied and appears a good candidate for further development and demonstration. Electrolytic oxidation of ferrous iron with recovery of hydrogen has been studied by EPA for treatment of acid mine waters.

The treatment of acid mine water results in a water impact in the form of dissolved solids and a solid impact in the form of a sludge. For example, in the limestone treatment of acid water, $CaSO_4$ is produced. This material is slightly soluble thus creating the dissolved solids impact, while the undissolved portion remains in the sludge.

Cost of Control

The cost of strip-mined land reclamation varies widely depending on the specific conditions. An average value of $1000 an acre(E-8) together with an assumed coal seam thickness of 2 feet give a cost of 1.1 cents per million Btu.

The cost of neutralization has been evaluated by OR and M for some representative cases. For a 10^6 ton/year plant producing 10^6 gallons per day water flow with 1000 mg/l acidity, the cost of neutralization was estimated to be 30 cents per 1000 gallons or 0.46 cents per 10^6 Btu.

The estimated costs for control are thus low enough that they should not seriously impact the cost of electric power from coal.

Underground Gasification

There is a possible alternative to the mining of coal underground with its attendant problems of worker health and safety. This involves the process of in-situ underground gasification.

In practice, the process of underground gasification would consist of

1. An arrangement, in accordance with the actual technique to be employed, of bored holes on a grid system from the surface to the coal seam, for (a) the introduction of the gasifying medium and (b) for conduction of the resulting fuel gas back to the surface.

2. Use of some procedure for rendering the coal bed porous between the intake and offtake ends of the grid system. Such fracturing along the coal seam has been investigated by several means. One method is termed electrolinking process results in gradual carbonization in a cross-section of the seam between the two points, thus resulting in fractures and pores for the passage of gases and allowing the necessary consecutive combustion and reduction reactions to occur. Hydraulic fracturing also has been investigated. Directional drilling and mining of passageways have been studied. Such fracturing is necessary to permit the necessary solid-gas reactions to occur, without (it must be stressed) permitting the bypassing of unreacted or only partially reacted gases to the offtake.

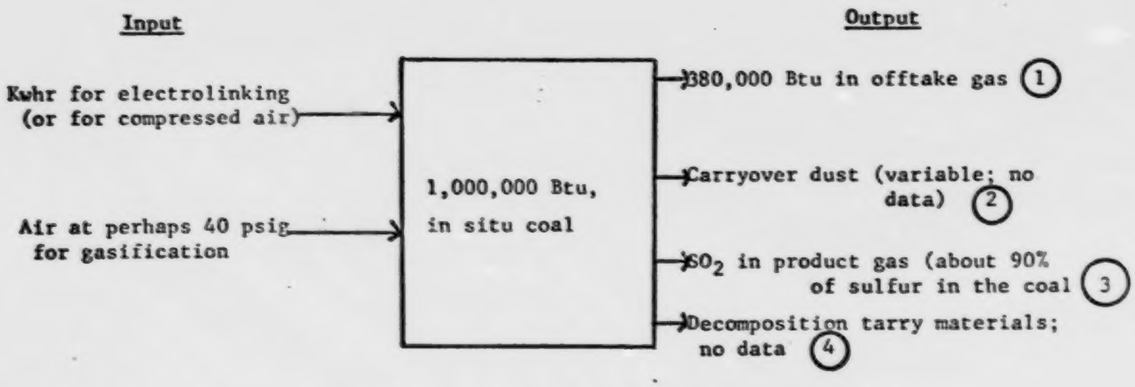
3. After preparation and fracturing, the coal is ignited at the air (or oxygen or air-oxygen mixtures) intake by burning some fuel until a path at proper temperature reached the offtake, with discard of the offtake gases. The gasifying air is admitted and, hopefully, the collection of the offtake fuel gas begins.

In work on underground gasification in the past, the gas produced, even with partially enriched air, had heating values in the range of about 80 to 100 or slightly more Btu/cu ft.(E-9) Even with oxygen, this value did not reach more than about 125 Btu/cu ft in the Bureau of Mines-Alabama Power Company tests. The cost of oxygen was deemed prohibitive, and in the Bureau's study of underground gasification costs the assumption for a commercial venture assumed the use of air and a fuel gas heating value of 100 Btu/cu ft.(E-10) Underground gasification appears to be thermally inefficient. The Bureau lists thermal efficiencies to be about 15 percent with hydraulic fracturing and up to 38 percent with an electrolinking fracturing system.(E-10)

Figure E-2 represents an attempt to depict a module representing the underground gasification process. The choice of base units is affected by the grid distance between intake and offtake in two directions, the thickness of the coal seam, and the density and/or heating value of the coal. We have chosen in this instance to use a unit based on the millions of Btu per foot of path (between intake and offtake).

Status of Underground Gasification

At one time, principally in the late 1940's and 1950's, there was interest in underground gasification in the United States, England, Japan, Russia, and several other countries in Europe. In the United States, pilot-plant experiments were carried on through 1959 under a joint


Input
Output
Kwhr for electrolinking (or for compressed air)
Air at perhaps 40 psig for gasification
1,000,000 Btu, in situ coal
380,000 Btu in offtake gas ①
Carryover dust (variable; no data) ②
SO2 in product gas (about 90% of sulfur in the coal ③
Decomposition tarry materials; no data ④

① This amount of gas produced is based on U.S. Bureau of Mines information, IC 8020, 1961. If hydraulic fracturing were employed, the same source specifies a thermal efficiency of 15.8 percent and a consequent output of 158,000 Btu per one million Btu in the in situ coal.

② Amount of carryover dust from underground is not given in the Bureau of Mines work. Should be small and readily removable.

③ The SO_2 in the gas depends on the sulfur content of the coal. Most of the sulfur in the coal gasified would appear in the offtake gas. The SO_2 would have to be largely removed if the underground operation were in areas of high sulfur coal. But the large part of the western coals, with low sulfur contents, could be gasified underground without removal of SO_2 from the product gas.

④ Some tar-forming material probably will be in the offtake gas. American work has not gone far enough to permit reasonable determination of the amount present. The amount could vary with the method and grid scheme. Russia has reported the use of washers and de-tarring equipment.

FIGURE E-2. INPUT-OUTPUT DESIGNATION FOR AN UNDERGROUND GASIFICATION MODULE effort by the U.S. Bureau of Mines and the Alabama Power Company. The results of the work, overall, were not very promising and the project was ended in 1959. Many problems were encountered, including that of producing a porous passageway through the coal bed for continuous operation, melting of the associated rock and blocking of passageways, bypassing of the reaction gases, etc.

By the early 1960's, the experimental work in the United States and England had been concluded, but some activity was still being reported in Russia, Czechoslovakia, and Japan. So far as is known, experimental work in Japan and Czechoslovakia is not now being carried on. A recent report by Arthur D. Little, Inc., to the Bureau of Mines (1972, published) on underground gasification concluded that the process is technically feasible but unproven economically after many countries had devoted many years of research, chiefly during the period 1945 to 1960. Since that time few underground tests have been reported and no significant research is believed to be under way anywhere through the first half of 1972.

However, it was reported in the fall of 1972 that the Bureau of Mines had decided to take another look at underground gasification.(E-11) By late this year, the Bureau will have drilled into a seam of coal in Wyoming, at a depth of 400 feet, with the purpose of investigating the production of a "low-sulfur, high-energy gas" from coal in place. Most certainly seam fracturing and new techniques will be studied, since almost all workers in the field of in-situ underground gasification have stated such to be a requirement justifying further work in this field.

As far as the large deposits of low-rank coals are concerned, the environmental problem from sulfur dioxide release from the underground produced gas upon burning would be minimal, since such coals are low in sulfur (much in the 0.5 to 0.8 percent range). Dust loadings would probably be low, but dust-removal equipment is available. Thus, the environmental emission on the surrounding area might be relatively low. However, gas produced in Russia has been with normal gas cleaning equipment--scrubbers, water-coolers, electrostatic de-tarrers, and sometimes sulfur removal, and, if a commercial underground gasification process becomes commercial in this country, the same cleaning procedures probably would have to be used.

It is impossible to judge the eventual technical and economic success with respect to the planned investigative effort in the current Bureau of Mines program. In any event, even initial success within ensuing years probably would not lead to any commercial ventures for at least the next 10 years.

During the underground gasification tests in the United States, the Bureau of Mines is believed to have spent about $2.5 million.(E-12) The amount spent by the Alabama Power Company might have totaled up to a million dollars, but this is only an estimate. In addition, one company, Electrofroe Corp., spent a considerable sum to develop and apply an electrolinking system, not only for use in underground gasification, however.

Up through 1959, the British had spent some $4.5 million on underground gasification tests.(E-12) Work was stopped shortly thereafter, Amounts spent in investigative effort in Russia, Japan, Czechoslovakia, and elsewhere are not known.

To develop underground gasification for use in the United States would represent a large investment in time and money. Judging from past expenditures and the lack of good results, to reach commercial status with a feasible and economic system would require many years of intensive effort and the expenditure of large sums of money, many tens of millions.

Cost of Producing Gas by Underground Gasification

In 1961, the Bureau of Mines published estimates of the cost of gas produced by underground gasification.(E-9) The resulting estimated costs were for two seam fracturing systems: (1) electrolinking, and (2) hydraulic fracturing. The assumptions made included: (1) coal seam thickness, 3 feet; (2) distance between boreholes, 155 feet; (3) distance between paths, 50 feet; and (4) 100 paths operating simultaneously during gasification. For the conditions stated, a 60,000 kw plant operated at a base load for 20 years would require a total of 4 square miles of coal acreage.

Katell and Faber(E-10) developed equations for gasification costs in which the main variables were (1) thickness of overburden, (2) gasification air inlet pressure, (3) electric power cost, and (4) thermal efficiency. Table E-1 summarizes the Bureau's estimated cost (1960 dollars) per million Btu in the produced gas with assumed power costs of $0.01 per kwhr, a gasification air pressure of 40, a production rate of 18.7 billion Btu per day, and 200 feet of overburden.

The total operating costs shown in Table E-1, 62.1 cents per million Btu for gasification employing electrolinking, and 77.1 cents per million Btu for hydraulic fracturing. These costs would increase by about 10 cents per million Btu (hydraulic fracturing) or 15 cents per million Btu (electrolinking) if power costs per kwhr were doubled.

The costs listed do not include anything for processing the gas after recovery for removal of sulfur, tarry material, or dust, nor is the cost of the acreage in terms of mineral rights, outright purchase, or royalties included. Thus, based on the results of the Bureau estimates, the estimated cost of the gas produced could well reach $1.00 per million Btu when acreage costs, increased power, labor, and material costs, and some gas cleaning costs were added under today's economic conditions. On the other hand, improved techniques which could result from further research and development might tend to offset some of the factors in the overall cost pattern.

TABLE E-1. UNDERGROUND GASIFICATION, ESTIMATED OPERATING COSTS

Item	Cents Per Million Btu Electrolinking	Cents Per Million Btu Hydraulic Fracturing
Site preparation and development	1.1	3.8
Power required for linking	10.8	
Labor required for linking	5.4	
Electrode and pipe cost	12.9	
Hydraulic fracture		7.7
Borehole drilling cost	4.8	15.4
Borehole pipe cost		12.3
Piping header cost	0.8	0.8
Transmission pipe cost	1.6	1.6
Linking air cost		10.8
Gasification air cost	22.0	22.0
Operating labor cost	2.7	2.7
Total Cost	62.1	77.1

Note: Assumptions:
Power cost, $0.01 per kwhr
Gasification air pressure, 40 psig
Gas production rate 18.7 billion Btu per day.

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APPENDIX F

GAS PIPELINE AND UNDERGROUND GAS STORAGE

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APPENDIX F

GAS PIPELINE AND UNDERGROUND GAS STORAGE

Gas Pipelines

The gathering of natural gas from gas wells, and their transmission to processing centers and to regions of distribution for consumption is done by means of pipelines. An integral component of the transmission circuit are pumping stations and wherever possible natural underground gas storage facilities used primarily by gas distributors during low consumption periods.

Environmental Emissions

Other than the need to clear and maintain an overland easement, the pipelines in the continental United States present a minimal impact on the surroundings they traverse (after the initial installation). The operation of such pipelines, however, does present some environmental emission parameters. If only the major transmission lines leading from the processing centers to remote distribution centers near centers of population are considered, movement of the gas at 750 psia through the pipelines requires strategically located compressor stations to maintain such pressures. The compressors are operated by gas engines which use as fuel the natural gas they are compressing. The amount of fuel consumed in 1970 to transmit 17.809 x 10^{12} ft^3 of natural gas to various distribution centers was 0.743 x 10^{12} ft^3 or about 4.1 percent.(F-1) The emission from such an operation is primarily NO_x as a result of the internal combustion of natural gas in the engines and is reported to be about 7300 lb NO_x per 10^6 ft^3 of natural gas consumed.(F-2) At this rate about 0.304 pound of NO_x per 1000 ft^3 of natural gas pumped is emitted.

As the need (and cost) of natural gas continues to increase, more "naphtha" is being used for fuel to operate compressor stations.(F-1) With the combustion of a higher molecular weight hydrocarbon larger quantities of pollutants other than NO_x will be emitted from engines designed for using natural gas. As this trend expands, techniques presently being developed for the gasoline automobile engine will have to be employed to meet the upcoming stringent Federal emission requirements for such engines.

Underground Gas Storage

In various parts of the country, natural gas companies operate underground gas storage fields. These fields are composed of various types of porous rock formations which are suitable to act as storage reservoirs.

The major use of these reservoirs is to smooth out seasonal fluctuations in gas usage. Thus, during the summer, when gas requirements are relatively low, gas will be pumped down into the reservoir. In the winter, this gas is then available to augment the normal gas flow.

In addition to this major use, the gas reservoirs contain quantities of valuable hydrocarbon liquids which are often brought up with the gas. After separation, these liquids can be sold for additional revenue.

The two major environmental emissions of the gas storage are (1) gas pressurizing and (2) leaks.

Environmental Emissions

Gas Pressurizing. The gas to be stored in the reservoir is pressurized to a higher pressure than the final use pressure. The reason for this is that there is considerable pressure drop as the gas flows through the reservoir into the delivery system. Typically, 1800 psi is used to fill the reservoir, the delivery pressure upon withdrawal is about 650 psi, and the gas is further throttled to about 550 psi pipeline pressure.

Emissions associated with the compression of gas from 550 to 1800 psi during the summer (about 6 months) can be considered an environmental emission. As natural gas is readily available to the storage site, gas engines are used to power the compressors. It can be calculated that about 0.014 ft^3 of gas must be burned to compress 1 scf of natural gas from 550 to 1800 psi (overall efficiency of 25 percent). The combustion of this gas would result in 0.0006 lb of NO_x released to the atmosphere per scf of natural gas stored. Calculations are based on an emission factor of 4300 lb of NO_x per 10^6 ft^3 of gas.(F-1) For a typical flow of 200 x 10^6 cubic feet per day injected into storage, a total of 600 tons of NO_x would be released into the atmosphere daily.

Gas Leakage. Several gas storage reservoirs in the country are confronted with gas leakage vertically. This gas can accumulate in the upper formations of the reservoir, and even escape into the atmosphere resulting in a pollution problem, as well as a safety hazard. Bernard and Holm (F-3) have studied the use of foaming agents and found that one application of about 0.3 pound of these agents per barrel of pore space would result in a 99 percent decrease in the leakage problem.

Assuming a 10 percent by volume pore space, and a cost of $1.00 per pound of foam, control of gas leakage would cost $0.04/1000 scf of gas.

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APPENDIX G

LNG TRANSPORTATION, HANDLING, AND STORAGE

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APPENDIX G

LNG TRANSPORTATION, HANDLING, AND STORAGE

Summary

Liquefaction of natural gas in overseas locations having a substantial surplus such as Algeria, Libya, Venezuela, and Alaska and shipment to gas-short areas such as Japan, U.S. East Coast, Spain, and Italy is increasing in popularity. For the United States, LNG is being used mainly for peak shaving, that is, augmenting pipelined gas during times of peak demand. Thus, the high cost has only a small effect on the overall average price.

Pollution due to the transportation, storing, and gasification of LNG is negligible and energy requirements are small. Pollution and energy costs of liquefaction, storage, and transportation on foreign soil and the high seas are beyond the scope of this study.

Environmental Impact of Spills

The environmental impact of spills of LNG needs to be considered, realizing that spills are more of a safety hazard than pollution hazard. The hazard is threefold--freezing, asphyxiation, and fire. Spills on ground would result in rapid evaporation initially that would cool the ground and slow the boiling. Plants and animals frozen in the process probably would be killed or injured. Spills into water result in very rapid boiling. Under certain conditions, a spill on water can produce an explosion-like eruption, but recent studies indicate that these eruptions are not likely to cause any damage. The gas released in a LNG spill, principally methane, does not support life and thus can be suffocating. Large spills can give a cloud of gas that can spread to an ignition source and then burn. As a matter of fact, this happened in one of the first LNG installations in the 1940's, killing more than 100 people. A mixture of vaporized LNG and air that is within the flammable limits will burn if ignited. Therefore, air is rigorously excluded from storage tanks. Obviously the spill of a tanker load of LNG resulting in a fire could result in a catastrophe. Since the safety hazard is high, elaborate precautions are always taken so that environmental impact multiplied by the probability of an incident is quite low. To date there is not enough experience with LNG to quantify this further.

LNG Tankers

Modern LNG tankers carry 0.5 to 1.5 billion scf of gas in liquid form at near-atmospheric pressure, utilizing well-insulated tanks to maintain the cargo at its boiling point (near minus 260 F) with a small boil-off rate. Future tankers will be larger with a 2.76 billion scf tanker already on order. If the natural gas is available at 5-10 cents per million Btu, the value of LNG is 30-40 cents loaded aboard ship and 60-70 cents delivered to the U.S. port.(G-1) The field cost of gas is expected to rise and the cost of shipping is expected to decrease as economies of scale are realized. The value of LNG delivered but not unloaded in 1990 is estimated by Battelle to be 70-90 cents per million Btu. On the loaded voyage, the fuel is primarily boil-off (0.3 percent of the cargo per day), supplemented by fuel oil. On the return trip a small amount of LNG is carried so that evaporation will keep the tanks chilled. This boil-off supplements the fuel oil used on the return trip. The pollutants consist primarily of SO_2 from sulfur compounds in the fuel oil. Pollution in the United States will occur only in the last few hours of the voyage, 2 days in port, and the first few hours on departure. The values will be on the order of 10^{-4} pounds of pollutants per million Btu of LNG delivered and hence have been judged negligible.

LNG Port Facilities

The port facilities consist of docks, storage, gasification, and general administrative and maintenance facilities. Storage and gasification are treated as separate modules elsewhere.

The docks, administrative, and maintenance facilities are negligible energy users and pollution sources. Spillage and release to the atmosphere is kept to a minimum for safety's sake. The land use is small compared to storage tanks and gasification facilities and difficult to relate to throughput of LNG.

LNG Storage

The simplest situation is in a base-load LNG plant where gasification is more or less continuous. Here storage is related to expected rate and size of shipments, and the boil-off of 0.1-0.3 percent per day is merely compressed and added to the mains. On the other hand, a peak shaving unit may receive only a few shipments over the period December to May and must keep it on hand until needed. The tanks will hold on the order of 10 days' supply. Here it is essential to keep losses to a minimum and to reliquefy the boil-off. The terminal storage for a base load plant will add about 40 cents per million Btu to the cost of LNG. Peak shaving storage will add an additional 60 to 90 cents per million Btu.(G-1)

LNG storage does not produce pollution or use significant amounts of energy. Compressors and pumps required will use electricity or fuel but will not have much impact on the environment.

LNG Gasification

Gasification plants can supply heat for vaporization in three ways: by warming with ambient air (through appropriate heat exchangers), by warming with ambient water, or by burning fuel. Current U. S. practice is to burn natural gas, achieving about 90 percent efficiency (that is 11 percent extra heat). If flame temperatures are kept below 2000 F so that NO_x is not formed, there is essentially zero pollution. This ignores power used for pumps and the pollution produced by them. The gas is produced at low gauge pressure and is compressed for use in city gas mains.

The value of vaporized gas is \$1.05-\$1.15 per million Btu for a base load operation (none in the United States at present) and \$1.70-\$2.20 for a peak shaving operation (assuming 5-10 cent gas in Algeria).(G-1) By 1990 the field cost of gas will have risen, transport will be cheaper, and liquefaction facilities will be cheaper per unit gasified due to economies of scale and accumulated experiences. Approximately the same price can be expected for gas from each type of operation in 1990 as today.

Currently no attempt is made in the United States to utilize the cooling power due to latent heat of vaporization available in the gasification. When large base-load LNG facilities are built, this probably will be done, lowering the heat input, pollution, and cost. However, this puts the gas utility into a nonregulated business, requires additional capital, etc. Thus, the data developed here represent a "worst case" for 1990.

Reference

G-1. Paul C. Johnson, Technology and Economics of Transporting and Storing LNG, American Institute of Chemical Engineers, Dallas, Texas, February, 1972.

APPENDIX H

OIL TRANSPORTATION ON INLAND WATERWAYS

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APPENDIX H

OIL TRANSPORTATION ON INLAND WATERWAYS

Summary

Inland waterways provide a major economic means of transporting petroleum and petroleum products. In 1971, 211.5 million tons, or almost 40 percent of the total freight traffic on inland waterways was these products. The average towboat handling petroleum and petroleum products has from 3200 to 4500 horsepower (hp) and can push barge tows of from 15,000 to 25,000 net tons, although larger towboats up to 9000 hp capable of handling tows up to 50,000 net tons are in use.

Most of the towboats are powered by diesel engines, so air emissions are low per unit of product handled. Other air emissions are from release of hydrocarbons during the loading and unloading of barges. The major pollution threat is the possibility of major oil spills that could occur from a disaster to one or more barges in a tow. There is a continuing improvement in the development and maintenance of river channels, the handling of river traffic, and the design of barges and towing methods. The safety record of handling petroleum and petroleum products has been good. Frequency and severity of injuries are in the same range as pipeline transportation of oil and gas. Land requirements are primarily those required for product storage at the various terminals.

Technical and Economic Characteristics

In 1971, transportation on inland waterways of the United States (exclusive of the Great Lakes) amounted to 560.5 million tons. Crude oil and various petroleum products accounted for about 211.5 million tons, or 37.7 percent of the total net movement broken down as follows:

	10^6 Tons
Crude petroleum	57.8
Gasoline, including natural gasoline	44.2
Jet fuel	6.2
Kerosene	2.6
Other petroleum and coal products[a]	100.2
	211.0(H-1)

(a) Residual fuel oil is believed to be the primary component.

In comparison, net movement of bituminous coal and lignite amounted to 109.5 million tons, and sand, gravel, and crushed rock amounted to 75.4 million tons.

Breakdowns in movement of crude petroleum and petroleum products by major inland waterways are shown in Table H-1.

Barge units navigate about 25,000 miles of inland waterways. The average towboat handling petroleum products has from 3,200 to 4,500 horsepower and can push bargetows of from 15,000 to 25,000 tons. Larger towboats with about 9000 hp can handle bargetows up to 50,000 tons. Upstream speeds on the Mississippi/Ohio Rivers of from 5 to 8 miles per hour can now be attained with maximum loads.(H-2) This would indicate a horsepower requirement of .18 to .21 hp per ton of cargo.

As of January 1, 1971, there were 3,185 tank barges, having a cargo capacity of 6,330,298 net tons.(H-1) Of these, 2,581 with a cargo capacity of 4,753,480 net tons operated on the Mississippi River System and Gulf Coast Intracoastal Waterway; 581 with a capacity of 1,521,222 net tons operated on the Atlantic, Gulf, and Pacific Coasts; while 23 with a capacity of 55,596 tons operated on the Great Lakes.

The average size of tank barges is about 2,000 tons. Assuming an average tow of 20,000 tons, the transportation of 211.5 million tons of petroleum and petroleum products would require 10,575 tows. Based on total tank barge capacity and assuming a 90 percent operating efficiency, the number of tows that could be operated on inland waterways at any given time would be about 283 (6,275,000 x .90 ÷ 20,000). On the same basis, the movement of 211.5 million tons of petroleum products with barge capacity of 6,275,000 tons operating at 90 percent efficiency would require about 37.5 round trips per barge, or a total elapsed time of slightly less than 10 days per round trip.

No figures have been obtained for average distance per trip for petroleum and petroleum product shipments. However, average distance per trip for all inland waterways cargo is 325 miles. This would indicate a round trip distance of 650 miles for petroleum and petroleum product barges.

Environmental Emissions

Using the average fuel consumption rate for motor ships of 0.34 pound/hp-hr,(H-3) and a horsepower requirement of 0.18 to 0.21, the fuel consumption would be 0.0612 to 0.0714 pound per hour per ton of cargo. Assuming an average speed of 6 mph, the fuel consumption per mile per ton would be 0.0102 pound to 0.0119 pound. Crude oil has an average volume of 6.77 barrels per ton making a fuel consumption per barrel mile of from 0.00151 pound to 0.00175 pound.

TABLE H-1. PETROLEUM AND PETROLEUM PRODUCTS (Millions of Tons)

	Inland Waterways			Ocean Going		
River	Crude	Gasoline Kerosene Jet Fuel	Other Petroleum and Coal Products	Crude	Gasoline Kerosene Jet Fuel	Other Petroleum and Coal Products
Upper Mississippi		5.8	6.1			
Mississippi	17.8	21.0	21.3	21.3	3.9	8.7
Ohio	8.0	13.6	6.8			
Illinois Waterway		2.5	5.2			
Calumet-Sag Channel		0.3	0.7		0.1	1.4
Allegheny/Monongahela		1.2	1.2			0.3
Kanawha		0.7	0.3			
Cumberland		1.4	0.5			
Tennessee		2.0	1.4			
Gulf Intercoastal Waterway	34.5	14.1	18.6		0.1	0.1
Subtotal	(60.3)	(62.6)	(62.1)			
Houston Ship Channel	4.3	1.5	6.1	2.3	10.9	9.9
Black Warrior, etc.	1.0		0.5			
Appalachula, etc.		0.1	0.2			
James River		0.3	3.1			
Atlantic Intercoastal Waterway (Norfolk to St. Johns River)		0.3	1.0			
Atlantic Intercoastal Waterway (St. Johns River to Miami)			0.7			0.1
Delaware	2.0	4.5	11.2	47.6	7.9	20.4
Potomac		0.6	3.4		0.3	2.6
Chesapeake Bay	0.3	10.6	5.8			
Hudson River		3.5	8.7		1.3	4.2
New York State Barge Canal		0.7	1.6			
Columbia		0.3	0.6	0.3	1.4	2.6
Sacramento		0.2	0.1			
San Joaquin	—	—	0.4	—	—	0.4
Total	67.9	85.2	105.5	71.5	25.9	50.7

NOTE: Duplication of movement exists.

Source: Inland Waterborne Commerce Statistics, 1971, The American Waterways Operators, Inc., Washington, D. C.

Diesel fuel has a heating value of about 19,800 Btu per lb so Btu requirements would be 29.9 Btu to 34.7 Btu per barrel mile. Assuming an average Btu content of 5.8 million Btu per barrel of petroleum shipped, the Btu requirements per million Btu would be 5 to 6 Btu per mile, or an average round trip of 650 miles would require 3250 Btu to 3900 Btu per million Btu of product transported, or an average of about 3575 Btu. The fuel consumption while in port, assuming an average of two days in port per trip and a consumption of 660 gallons per day of diesel fuel, would be $\frac{660 \times 2 \times 138{,}700}{20{,}000 \times 6.77 \times 5.8} = 233$ Btu per million Btu of product. This would indicate a total Btu requirement of about 3800 Btu per million Btu's of product transported.

Oil Spills

Contamination of inland waters from oil is a major environmental problem. Spills from barge accidents and losses occurring in loading and unloading operations contribute only a small fraction of the total pollution occurring on inland waterways. During the short time period for this study, quantitative data have not been found for the amount of oil contamination caused by barge movement of petroleum and petroleum products. If one assumed that the average loss per year per barge amounted to 1/10 of 1 percent of barge capacity, spillage would be about 6330 tons, or 0.03 percent of tonnage shipped annually. Assuming an average weight of 300 pounds per barrel, the spillage per barrel shipped would amount to 0.09 pound. For comparison, oil spills from pipeline shipments is estimated to be 0.023 pound per barrel.

It should be recognized, however, that the potential threat of a major spill from barge operations would be much more severe than the threat of a pipeline incident. Individual batch movements of oil on inland waterways of up to 50,000 tons (350,000+ barrels) are comparable to tankers used in U.S. trade. While the contents of individual barges are much less and multicompartation with void spaces fore and aft are used, spills of large quantities of oil are a constant threat requiring prompt action to prevent major disasters from occurring.

The safety record in handling barge movement of oil has been quite good. Frequency and severity of accidents in marine and inland waterways operations are similar to those in pipeline operations.

Continuing improvement in the development and maintenance of river channels, the handling of river traffic, and in the design of barges and towing methods may be expected, which will tend to offset the dangers from increased traffic on inland waterways.

Land use requirements for barge movements of oil are primarily for storage at the various terminals.

References

H-1. Inland Waterborne Commerce Statistics, 1971, The American Waterways Operators, Inc., Washington, D.C.

H-2. Environmental Conservation, The Oil and Gas Industries, Vol. 2, National Petroleum Council, February, 1972.

H-3. Environmental Protection Agency, Office of Air Programs, Compilation of Air Pollutant Emission Factors (Revised), February, 1972.

APPENDIX I

TRANSPORTATION MODULE FOR COAL AND OIL TRANSPORT BY RAIL, TRUCK, AND PIPELINE

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APPENDIX I

TRANSPORTATION MODULE FOR COAL AND OIL TRANSPORT BY RAIL, TRUCK, AND PIPELINE

Summary

Assessment of the emissions from the transport of coal and oil by rail, truck, and pipeline has been accomplished through an evaluation of the fuel quantities and distances transported by the various transportation modes, a determination of the power per quantity-mile of the transporting device, and a correlation of these collected data to establish actual air pollution emissions. Subjective data on transportation accidents, construction and maintenance, land use, noise pollution, and aesthetics are considered with reference to the transportation modes.

Of the 695.4 million tons of coal shipped from the production districts, 495.8 millions tons or 71.3 percent is shipped by rail and the remainder is shipped by truck, barge, and other transportation modes. Consequently, the rail transport of coal dominates the other transport modes. Exhaust emissions into the air, particle tailings from the top of railroad cars, and land right-of-way appear to be the significant factors associated with coal transport. Air emissions were calculated based on the prime mover required to transport the coal. Basically, rail and truck transport of coal is primarily dependent on petroleum products, and no immediate alternates to the use of petroleum appear technically or economically feasible. Emissions to the air of NO_x, HC, CO, and SO_2 were calculated for rail transport of coal resulting in 116.7, 9.07, 89.9, and 8.31 thousand tons/year of these pollutants exhausted to the atmosphere, respectively.

Land use is perhaps the largest environmental factor associated with coal transport. Land right-of-ways of 3760 square miles are currently held by the railroads. Since 16 percent of the total material shipped by rail is coal, 616 square miles of right-of-way may be attributable to coal transport.

Crude oil is transported primarily by pipeline (77.4 percent) and the remainder by water (21.5 percent), tank cars, and tank trucks. Of the 1.888 million horsepower required to operate the oil pumping stations, 1.43 million horsepower is developed from electrical power and the remainder from gas and diesel engines. Since the electrically powered units contribute to the emissions more from a land-use and central power station standpoint, the gas and diesel driven stations were analyzed on the basis of emissions to the air.

Future reduction in fuel consumption is likely provided engine efficiencies are improved. Conservatively, it is assumed that engine efficiencies will remain at the current level and environmental changes occur as a result of the greater demand for coal and oil transport. As a result, the future projections of the emissions from the transport of coal and oil are based solely on the demands projected for the electrical requirements.

Emissions

Evaluation of the quantity of coal and oil and distance shipped by various transportation means is required to determine the overall emissions from the transport systems.

Coal

Distribution of coal is primarily accomplished by rail, barge, and truck. Of the total production in 1970, 81.3 percent of the coal was shipped by rail and barge, 12.2 percent by truck, 0.7 percent by all other means of transportation; 5.8 percent of the 1970 coal production was used at the mine in generating plants.(I-13) The 0.7 percent transported by other means includes the transport of coal using slurries in pipeline systems.(I-24) The total production for 5601 active mines for 1970 was 695,400,000 tons.(I-10) The locations of these mines are shown in Figure I-1. The objective of the quantity-transport evaluations is to combine the data to establish the ton-mile of coal transported by each transportation means.

Battelle's Columbus Laboratories performed a study that related the 1975 transport of coal from the mines to specific areas of the United States.(I-10) Table I-1 shows the compiled data on the quantity and distance shipped for each of the production districts. The percentages cited above were used to establish the ton-miles of coal shipped by rail and truck. Quantities shipped by other means and by barge are also included in the data given in Table I-1. Note that the quantity of coal shipped by rail and barge is 81.6 percent of the total with an assumed split of 71.6 percent by rail and 10 percent by barge.

Unit Emissions Evaluations. Having established the quantity and distance transported of the coal used in electrical production, establishment of conversion factors is required to determine the physical emissions exhausted into the atmosphere as a result of coal transport for electrical power generation.

Data presented in the previous section established the quantity of coal and the distance transported from each of the 23 production areas of the United States. A conversion is needed to relate ton-miles of coal to emissions of NO_x, CO, HC, and SO_2. This is to be accomplished by assuming

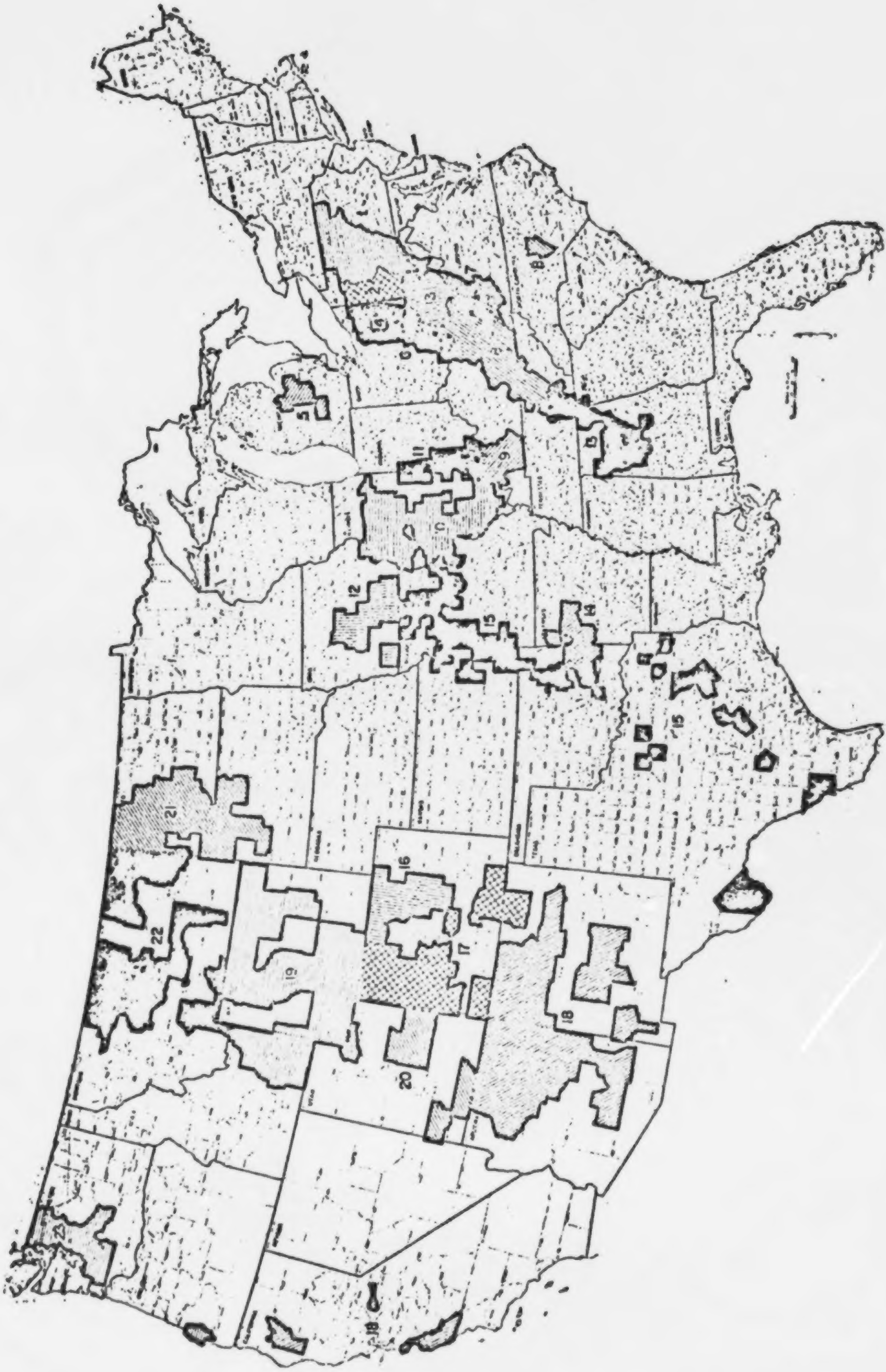

FIGURE I-1. FUEL SUPPLY DISTRICTS--COAL

TABLE I-1. DATA ON COAL TRANSPORT FROM VARIOUS PRODUCTION DISTRICTS

Production(a) District	Shipments(b) in Millions of Tons	Average Mileage Shipped	Millions of Ton-Miles Shipped			
			Rail(c) 10^6	Barge(c) 10^6	Truck 10^6	Other 10^6
1	51.7	175	6,450	904.7	1,131	561.3
2	26.6	200	3,793	532.0	665	332.2
3	47.9	116	3,961	555.6	695	344.4
4	71.0	208	10,530	1,476.8	1,846	915.2
5	(No Data Available)					
6	13.4	200	1,911	268.0	335	166.0
7	25.6	305	5,567	780.8	976	484.2
8	198.9	293	41,552	5,827.8	7,224	3,613.2
9	62.4	395	17,574	2,464.8	3,081	1,528.2
10	73.4	237	12,402	1,739.5	2,174	1,078.5
11	27.1	200	3,864	542.0	677	336.0
12	0.8	250	143	20.0	25	12.0
13	27.6	80	1,574	220.8	276	137.2
14	0.2	250	36	5.0	6	3.0
15	11.7	206	1,718	241.0	301	149.0
16	0.9	200	128	18.0	22	11.0
17	7.7	200	1,098	154.0	192	95.0
18	11.8	390	3,281	460.2	575	285.0
19	12.8	365	3,331	467.2	584	289.4
20	5.1	200	727	102.0	127	63.0
21	8.9	180	1,142	160.2	200	98.8
22	8.3	847	5,024	704.6	881	436.4
23	1.6	270	308	43.2	54	26.8
Total	695.4		126,117	17,688.2	22,110	10,967.0

(a) Reference I-13.

(b) Reference I-10.

(c) Reference I-13 illustrates the total shipment from rail and barge to be 81.3 percent, the percentage of each was assumed to be 71.3 percent and 10 percent, respectively.

a 3,000 horsepower requirement for each 2,000 tons of gross load in a locomotive-train system.(I-8) At an average speed of 44 mph, a conversion to train horsepower-hour from gross ton-miles may be established as follows:

$$\frac{3{,}000\ \text{hp}}{[2{,}000\ \text{g tons}]\ [44\ \text{mi/hr}]} = 0.0341\ \frac{\text{hp-hr}}{\text{ton-mi}}\ ,$$

for maximum power conditions. Derating this figure to account for the percent of time at the various throttle positions is required and Table I-2 illustrates the proposed load-speed cycle for locomotive-emissions testing that can be used for this purpose.

TABLE I-2. LOCOMOTIVE LOAD-SPEED CYCLE (I-16)

Throttle Position	Engine, rpm	Percentage of Rated Horsepower, approx.	Percentage of Time
8	900	100	30
7	815	86	3
6	730	86	3
5	645	51	3
4	560	35	3
3	480	23	3
2	395	12	3
1	315	5	3
Idle	315	0.75	41
Dynamic Brake	-	3	8

Excluding the idle and brake periods, the load factor or the average horsepower divided by the maximum horsepower is 0.749. In addition to this load factor, a relationship between the gross-to-net-weight ratio is required. Data from the American Railroad Association reveal that the ratio of average gross tonnage to average net tonnage is 2.3481.(I-8) As a consequence, the 0.0341 hp-hr/gross ton mile can be converted to a usable factor to be directly applied to the accumulated ton-mile data by applying the load factor and gross-to-net weight ratio as follows:

$$[0.0341\ \frac{\text{hp-hr}}{\text{n ton-mi}}\ ][2.3481\ \frac{\text{g ton}}{\text{n ton}}\ ][0.749] = 0.0599\ \frac{\text{hp-hr}}{\text{ton-mi}}\ .$$

Emission estimates on railroad locomotives of 15.43 tons of NO_x per 10^6 hp-hr, 1.213 tons of HC per 10^6 hp-hr, 11.9 tons of CO per 10^6 hp-hr and 1.1 tons of SO_2 per 10^6 hp-hr have been recently reported.(I-16) Using these data and the conversion factor 0.0599 hp-hr/ton-mi as presented above, together with the data presented on Table I-1, provides the quantity information required to formulate the actual emissions resulting from the transport of coal; these calculated data are presented under the railroad emission section of Table I-3.

Unit emissions as a result of coal transport by truck to the electric utilities requires an evaluation of the horsepower-hour necessary to ship a quantity of coal a given number of miles. For a truck with a gross vehicle weight of 60,000 pounds, the level-road horsepower to maintain a 50 mile per hour speed is 270. Applying these data to establish the truck horsepower from gross ton-miles results in the following:

$$\frac{\text{hp Required}}{(\text{Vehicle Weight})\ (\text{Velocity})} = \frac{\text{hp-hr}}{\text{g ton-mile}}$$

Using the values stated above, the conversion factor is 0.15 hp-hr/g ton mi at 60 mph and 0.107 hp-hr/g ton mi at 50 mph. The average speed of trucks on main and rural highways in 1968 is 54 mph, and on this basis it is assumed that 40 percent of the travel time is at 60 mph and 60 percent of the travel time is at 50 mph. Taking a weighted average, the conversion factor of ton-miles to horsepower-hour for trucks becomes

$$\frac{(0.107)\ (60) + (0.15)\ (40)}{100} = 0.1242\ \frac{\text{hp-hr}}{\text{g ton-mile}}$$

This figure is based on gross tonnage of the vehicle weight as opposed to net tonnage. As a result, an estimated gross-to-net weight ratio must be determined. Calculations in Reference I-8 indicate that the gross-to-net weight ratio for trucks is 2.1531. Therefore, the conversion to be used in the emission calculations is

$$\left[0.1242\ \frac{\text{hp-hr}}{\text{g ton-mi}}\right]\left[2.1531\ \frac{\text{g ton}}{\text{n ton}}\right] = 0.267\ \frac{\text{hp-hr}}{\text{n ton-mile}}\ .$$

Applying this conversion factor to the truck data shown in Table I-1, the resulting horsepower-hour required to transport the coal quantity a given distance as designated is calculated and shown in the truck section of Table I-3.

Reported truck emissions of the various emissions are 11.6 tons of $HC + NO_x$ per million horsepower-hour, 6.6 tons of CO per million horsepower-hour, and 1.1 tons of SO_2 per million horsepower-hour.(I-8) Using these data and the horsepower-hour data determined above, actual truck emissions resulting from the transport of coal may be calculated. The results of these calculations are shown under the truck emissions data in Table I-3.

TABLE I-3. RAILROAD LOCOMOTIVE AND TRUCK EMISSIONS FROM COAL TRANSPORT FROM MINE TO ELECTRIC UTILITY

Production District	Hp-Hr. Required to Move the Ton-Mile of Coal of Table 1		Emissions (10^3 Tons/Year)						
			Rail				Truck		
	Rail	Truck	NO_x	HC	CO	SO_2	NO_x + HC	CO	SO_2
1	386.3	302	6.00	0.46	4.60	0.42	3.5	2.0	0.3
2	227.2	178	3.50	0.27	2.70	0.25	2.1	1.2	0.2
3	237.3	186	3.65	0.28	2.82	0.26	2.2	1.2	0.2
4	630.7	493	9.71	0.76	7.51	0.69	5.7	3.3	0.5
5	(No Data Available)								
6	114.5	89	1.76	0.14	1.36	0.13	1.0	0.6	0.1
7	333.5	261	5.14	0.40	3.97	0.37	3.0	1.7	0.3
8	2,489.0	1945	38.30	2.99	29.60	2.74	22.6	12.8	2.1
9	1,052.7	823	16.20	1.26	12.50	1.16	9.5	5.4	0.9
10	742.9	580	11.40	0.89	8.84	0.82	6.7	3.8	0.6
11	231.5	181	3.56	0.28	2.75	0.25	2.1	1.2	0.2
12	12.0	7	0.18	0.01	0.14	0.01	0.1	-	-
13	94.3	74	1.45	0.11	1.12	0.10	0.9	0.5	0.1
14	2.2	2	.03	-	0.03	-	-	-	-
15	102.9	80	1.58	0.12	1.22	0.11	0.9	0.5	0.1
16	7.7	6	0.12	0.01	0.09	0.01	0.1	-	-
17	65.8	51	1.01	0.08	0.78	0.07	0.6	0.3	0.1
18	196.5	154	3.02	0.24	2.34	0.22	1.8	1.0	0.2
19	199.5	156	3.07	0.24	2.37	0.22	1.8	1.0	0.2
20	43.5	34	0.67	0.05	0.52	0.05	0.4	0.2	-
21	68.4	53	1.05	0.08	0.81	0.08	0.6	0.3	0.1
22	300.9	235	4.63	0.36	3.58	0.33	2.7	1.6	0.3
23	18.4	14	0.28	0.02	0.22	0.02	0.2	0.1	-
Total	7.554.4	5903	116.30	9.07	89.90	8.31	68.5	39.0	6.5

(a) Based on emission factors from Reference I-8.

Related Factors. Physical emissions shown in Table I-3 directly reflect the environmental changes that occur with respect to the air pollution due to the transport of coal and oil. Additional factors should also be considered--for example, spillage, transportation accident potential, road and railway construction, right-of-way factors, noise pollution, effective land use, ecological factors, aesthetics, and the social well being. Most of these factors are not subject to quantitative analysis and as a consequence only a relative comparison between railroad and highway environmental factors is attempted.

Major environmental factors caused by railroad and highway transportation listed above have been compared on a relative basis with respect to construction, right-of-way, and land use. The primary areas of comparison include ecological factors, water pollution, air pollution, land pollution, noise pollution, aesthetics, and social well being. Reference I-8 has completed this type of evaluation, and the results are shown in Table I-4. The general environmental indicators are listed at the top of the table while environmental factors are listed on the left side of the table. If a comparison is established for the various factors, it is an indication that a major impact on the environment exists from both modes of transportation, and that the impact of one mode of transportation is greater than the other. In the event that a blank occurs on the table, no differences exist with respect to the major environmental factors.

The spillage of coal from either the railroad car or from the truck in the form of dust blown from the top of the load has also been considered. The coal companies are conscious of this factor since it results in a direct financial loss. As a consequence, several methods are employed by the transporting companies to minimize dust loss. Chemicals applied to the top of the load and load topping with an appropriate type of coal are examples of the current methods employed to prevent dust loss.

Environmental effects resulting from accidents can be compared based on the number of accidents per year by the railroads and by highway trucks. Figure I-2 shows the total number of accidents predicted for the railroads and motor carriers or trucks from 1956 and projected until 1980. In brief, accidents involving trucks are more frequent than those involving trains but the quantity of material involved in a single accident is significantly larger in the latter case.

With respect to spillage, transportation accident potential, road and railroad construction, right-of-way factors, noise pollution, effective land use, ecological factors, aesthetics, and social well-being, it is expected that increased energy needs existing in the United States will result in a proportional increase in the environmental factors. As a consequence, only the effects of increased transportation due to the electrical generation demands will be considered for future projections of environmental factors associated with the transportation of coal.

TABLE I-4. ENVIRONMENTAL IMPACT COMPARISONS OF HIGHWAY AND RAILROAD TRANSPORTATION MODES

Causes of Impacts	Ecological Factors	Pollution				Aesthetic	Social Well Being	
		Air	Water	Land	Noise		Human Interest	Human Betterment
A. Construction, Operation, & Disposal								
1. Materials used in manufacture	H > R	H > R	H > R					
2. Operation								
a. Exhaust		H >> R				H > R	H > R	H > R
b. Leaks and spills	R > H		R > H	R > H		R > H		
c. Lights						H > R		H > R
d. Stop and start		H > R			H > R	H > R		H > R
3. Goods transported								
a. Hazardous	R > H	R > H	R > H					H > R
b. Other bulk cargo								
4. Disposal		H > R		H > R		H >> R		
B. Right of Way (Adjacent/Operational)								
1. Materials used in construction	H > R	H >> R	H >> R			H >> R		
2. Construction operation		H > R	H > R	H > R	H > R	H > R		H > R
3. Locational considerations								
a. Highway/rail						H > R		
b. Drainage			H > R			H > R		
c. Lighting								
4. Maintenance and repair	H > R		H > R	H > R				
C. Land Use								
1. Direct (terminals, repair, refueling)		R > H			R > H	R > H		R > H
2. Indirect (Adjacent land uses)	H > R					H > R	H > R	H > R

Key
H Highway Freight Transport
R Rail Freight Transport
Blank No difference or major impacts.

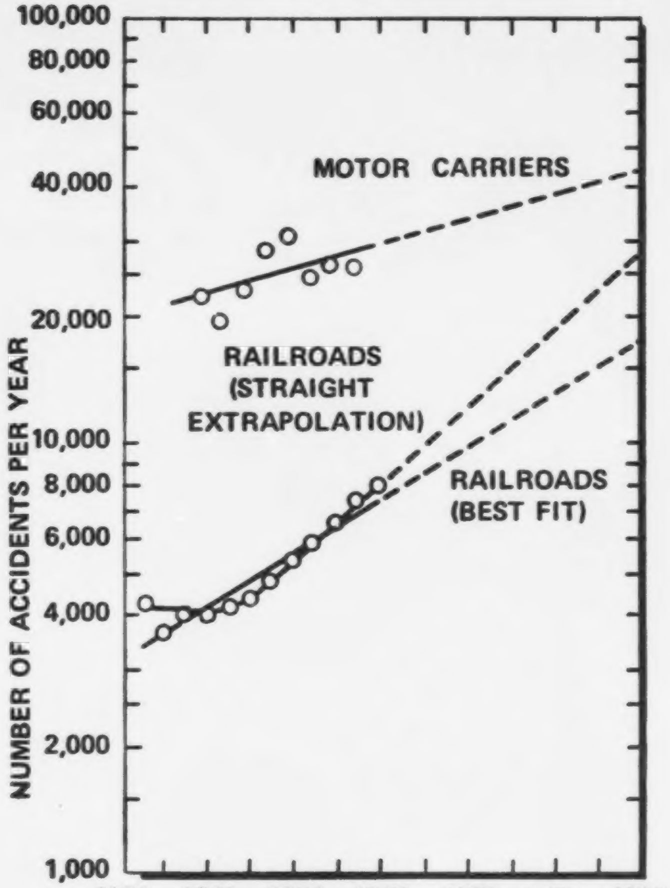

FIGURE I-2. TOTAL ACCIDENT PREDICTIONS

Projections of Environmental Factors. Figure I-3, depicting the quantity of coal transported to the various industries, illustrates that the percentage of coal shipped directly to electrical power utilities, has been approximately constant over the past few years. As a consequence, it is assumed that the environmental emission due to emissions from transportation systems will be increased on the same percentage basis as the electrical generation established in Appendix R of this report. On this basis, a projection of emissions was calculated and the results are shown on Table I-5.

Oil

A transportation network consisting of pipelines, tankers, barges, tank cars, and tank trucks carry the crude petroleum to refineries for processing. Of the crude oil received at the refineries in 1970, 77.4 percent was received by pipeline, 21.5 percent by water, and the remaining 1.1 percent by tank cars and tank trucks. Since this section of the report deals only with the pipeline, truck, and rail aspects of moving oil, the major factor of concern is with regard to the crude oil transport by pipeline.

Petroleum Administration for Defense (PAD) districts have been established as shown in Figure I-4 and quantity shipments between and within each PAD District are shown in Table I-6.

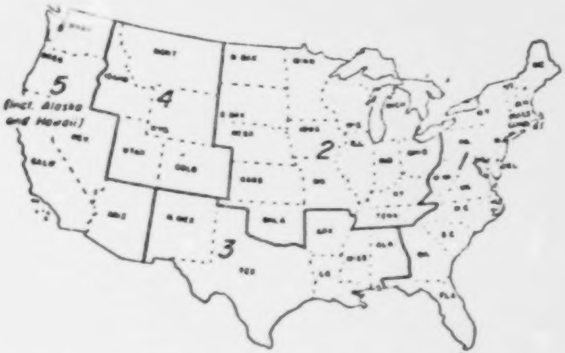

FIGURE I-4. DESIGNATION OF PETROLEUM DISTRICTS

These data illustrate that 66 percent, or 1,036,629,000 barrels, of the crude transported is received by refineries in the northeastern section of the United States.(I-14) Maps distributed by the Oil and Gas Industry also illustrate the predominance of the pipelines in the east to northeastern sector of the United States. As a result, the largest percentage of pumping stations that possess the potential for environmental impact with respect to emissions into the air are found in the eastern sector of the United States.

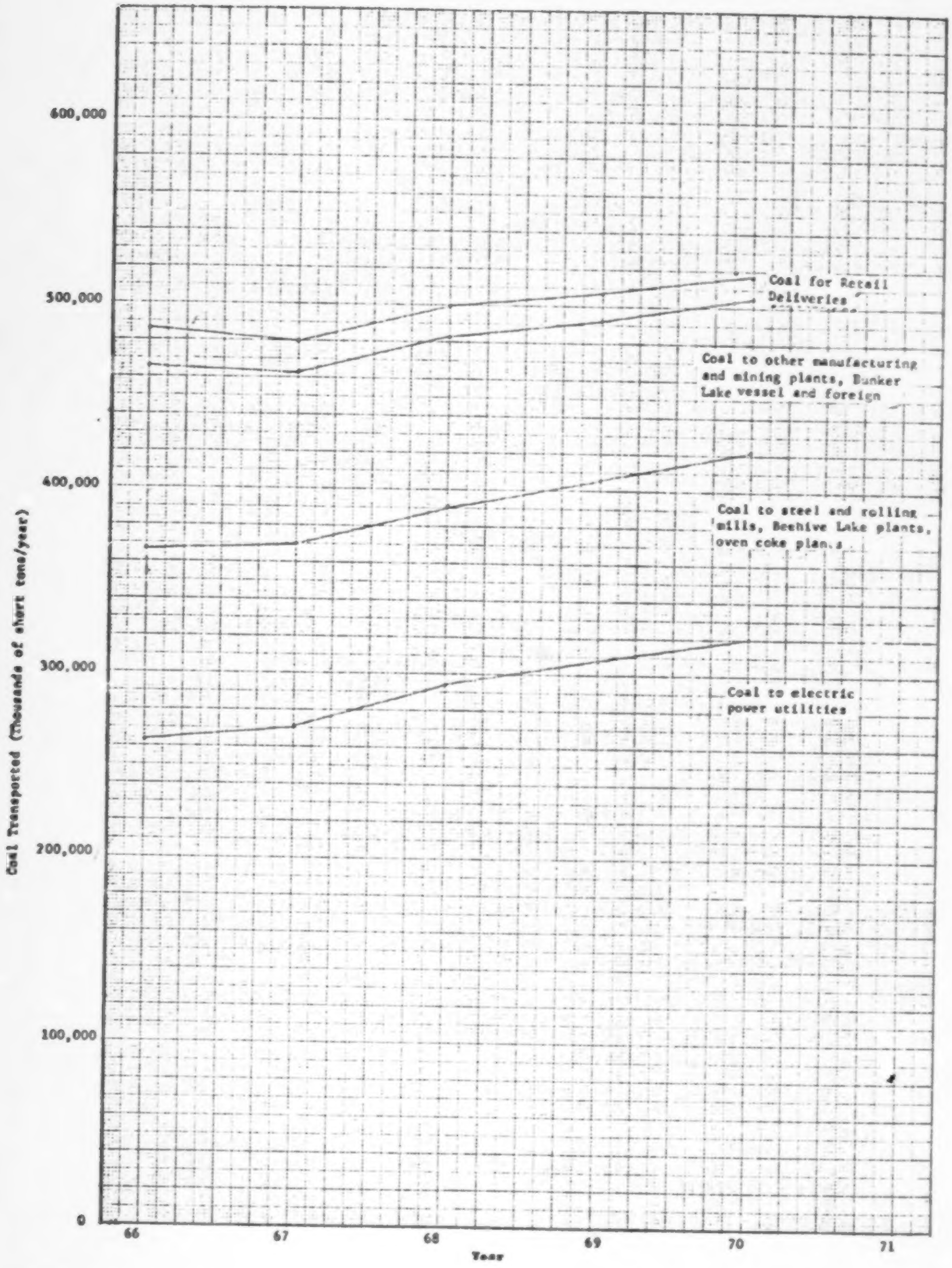

FIGURE I-3. CONSUMPTION OF BITUMINOUS COAL AND LIGNITE, BY CONSUMER CLASS, WITH RETAIL DELIVERIES IN THE UNITED STATES

TABLE I-5. PROJECTED EMISSIONS FROM TRANSPORT OF COAL FOR ELECTRICAL PRODUCTION

Method of Transport	Pollutant	Emissions (10^3 Tons/Year) 1972	1975	1980	1985	1990	1995	2000
Railroad	NO_x	75.0	116.3	141.4	163.0	183.9	203.0	224.0
	HC	6.25	9.07	11.0	12.7	14.3	15.8	17.4
	CO	58.0	89.9	109.3	126.0	142.1	157.0	173.3
	SO_2	5.36	8.31	10.1	11.64	13.1	14.5	16.0
Truck	NO_x + HC	44.2	68.5	83.3	96.0	108.3	119.7	132.1
	CO	25.2	39.0	47.0	54.2	61.1	67.6	74.5
	SO_2	4.2	6.5	7.9	9.1	10.3	11.3	12.5

TABLE I-6. CRUDE OIL TRANSPORTED TO REFINERIES BY STATE AND DISTRICT, 1970

(Thousand barrels)

Location of refineries receiving crude oil	Total receipts of domestic crude oil	Intrastate receipts	Interstate receipts from—							Interstate receipts from—											
				PAD district II						PAD district III					PAD district IV						
			PAD dist. I, total	Ill., Ind., Mich.	Kans.	Ky., Ohio, Tenn.	Nebr., N. Dak., S. Dak.	Okla.	Total	Ala., Ark., Miss.	La.	N. Mex.	Texas	Total	Colo.	Mont.	Utah	Wyo.	Total	PAD dist. V, total	Total interstate receipts
District I:																					
Delaware, Maryland	11,442	......	3,024	......	......	......	......	......	......	358	535	......	7,493	8,419	......	......	......	......	......	......	11,442
Florida, Georgia, Virginia	3,166	......	......	......	......	......	......	......	......	1,321	......	......	1,845	3,166	......	......	......	......	......	......	3,166
New Jersey	96,192	......	......	......	......	......	......	......	......	13,271	54,934	104	27,531	95,840	......	......	......	......	......	352	96,192
New York	1,251	......	......	......	......	......	......	483	483	......	51	......	692	743	......	23	......	......	23	......	1,251
Pennsylvania:																					
East	129,418	......	......	......	......	......	......	......	......	......	72,690	449	56,279	129,418	......	......	......	......	......	......	129,418
West	16,213	4,799	3,874	303	......	3,355	......	551	4,209	......	......	......	......	......	......	3,332	......	......	3,332	......	11,418
West Virginia	2,937	1,575	......	......	......	1,362	......	......	1,362	......	......	......	......	......	......	......	......	......	......	......	1,362
Total	260,619	6,373	6,898	303	......	4,717	......	978	6,058	14,950	128,210	553	93,842	237,586	......	3,355	......	......	3,355	352	254,246
District II:																					
Illinois	269,622	18,302	......	103	8,350	......	1,766	23,918	34,137	7,365	64,212	18,224	114,309	204,060	4,222	1,360	......	10,671	16,273	......	251,320
Indiana	183,629	6,470	......	1,274	11,130	5	3,759	23,333	39,501	......	16,011	10,218	34,231	60,457	1,134	8,223	......	29,123	38,480	......	177,465
Kansas	130,356	79,161	......	......	......	......	1,166	17,330	18,527	......	......	1,374	13,497	14,871	1,031	643	......	18,821	20,797	......	54,195
Kentucky, Tennessee	61,885	4,301	12	14,384	......	132	......	......	14,528	643	41,046	......	1,042	42,731	......	......	......	315	315	......	57,584
Michigan	35,661	11,150	......	2,419	......	......	......	......	2,419	......	......	......	13,667	13,667	......	......	......	8,019	8,019	......	24,104
Minnesota, Wisconsin	3,339	......	......	......	......	......	3,339	......	3,339	......	......	......	......	......	......	......	......	......	......	......	3,339
Missouri, Nebraska	31,733	......	......	......	1,022	......	554	3,712	5,290	......	......	8,104	12,710	20,814	......	......	......	5,651	5,651	......	31,733
North Dakota	18,142	17,147	......	......	......	......	......	......	......	......	......	......	......	......	......	995	......	......	995	......	995
Ohio:																					
East	21,173	4,109	......	1,986	431	......	......	843	3,260	......	10,222	......	......	10,222	1,122	......	......	2,460	3,582	......	17,064
West	115,757	7	......	14,706	......	......	28	3,623	18,358	3,778	38,001	2,524	49,175	93,478	122	47	......	3,745	3,914	......	115,750
Oklahoma	164,769	118,560	......	......	2,927	......	......	......	2,927	......	......	4,860	36,453	41,313	1,475	......	491	......	1,966	......	46,209
Total	1,038,389	256,006	12	35,053	20,960	137	12,646	82,707	151,515	11,786	169,532	84,301	295,324	530,873	9,113	11,487	491	78,005	99,095	......	782,383
District III:																					
Alabama	6,409	1,312	......	......	......	......	......	......	......	3,975	1,092	......	......	5,067	......	......	......	......	......	......	5,067
Arkansas	32,379	15,865	......	......	......	......	......	......	......	......	2,730	......	13,784	16,514	......	......	......	......	......	......	16,514
Louisiana	430,962	355,361	......	......	......	......	......	29	29	21,804	......	......	53,768	75,572	......	......	......	......	......	......	75,601
Mississippi	68,102	12,353	......	......	......	......	......	......	......	......	55,749	......	......	55,749	......	......	......	......	......	......	55,749
New Mexico	14,791	14,790	......	......	......	......	......	......	......	......	......	......	......	......	1	......	......	......	1	......	1
Texas	1,041,094	791,407	......	1	3	......	......	804	807	40	188,044	54,653	......	242,737	16	......	3,127	......	3,143	......	246,687
Total	1,593,737	1,194,118	......	1	3	......	......	833	836	25,819	247,615	54,653	67,552	395,639	17	......	3,127	......	3,144	......	399,619
District IV:																					
Colorado	13,248	2,014	......	......	......	......	......	......	......	......	......	......	......	......	......	2,298	24	8,912	11,234	......	11,234
Montana	26,373	11,330	......	......	......	......	......	......	......	......	......	......	......	......	......	......	......	15,043	15,043	......	15,043
Utah	40,145	10,236	......	......	......	......	......	......	......	......	......	42	......	42	13,687	159	......	15,938	29,780	87	29,909
Wyoming	46,720	45,579	......	......	......	......	6	......	6	......	......	......	......	......	632	503	......	......	1,135	......	1,141
Total	126,486	69,159	......	......	......	......	6	......	6	......	......	42	......	42	14,339	2,960	24	39,893	57,192	87	57,327
District V:																					
California	453,335	378,771	......	......	......	......	......	......	......	......	......	2,810	......	2,810	......	......	10,940	......	10,940	60,814	74,564
Other States	19,818	11,367	......	......	......	......	......	......	......	......	......	......	......	......	......	......	......	......	......	8,451	8,451
Total	473,153	390,138	......	......	......	......	......	......	......	......	......	2,810	......	2,810	......	......	10,940	......	10,940	69,265	83,015
Total United States	3,492,414	1,915,794	[1]6,710	35,417	20,862	4,854	12,692	84,576	158,409	52,515	545,356	112,350	456,718	1,168,919	23,466	17,992	14,542	118,794	174,826	[2]69,734	1,576,620
Daily average	9,568	5,249	18	97	57	13	35	232	434	144	1,494	308	1,251	3,197	64	49	40	326	479	191	4,319

[1] Florida, 3,024; New York, 1,455; Virginia, 12; West Virginia, 2,219.

[2] Alaska, 62,650; Arizona, 2,481; California, 4,478; Nevada, 110.

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The Interstate Commerce Commission has reported a total of 171,782 miles of interstate pipelines transporting crude oil and petroleum products as of December 31, 1970. It is estimated that the older pipeline pumping stations are located on the average of every 40 to 60 miles apart, whereas the newer pipelines have pumping stations on the average of 100 to 150 miles apart.

Of the 1.888 million horsepower used in pumping oil across the United States, electric powered pumping stations develop 1.43 million horsepower or 76 percent of the total, diesel powered pumping stations develop 0.31 million horsepower or 16.3 percent of the total, and gas powered pumping stations develop 0.15 million horsepower or 7.7 percent of the total.(I-25) Assuming a specific fuel consumption of the stationary diesel engine at 0.39 pound fuel per brake horsepower-hour(I-26) provides the basic quantization information for establishing the diesel emissions. Conversion data on the gas engine were accomplished assuming an equivalent thermal efficiency with respect to the diesel and comparing the fuel heating values.

Unit Emissions Evaluation. As indicated in the quantity evaluation section, 77.4 percent of the crude oil received by refineries in 1970 was transported by pipeline, and almost all of the remainder by water. As a consequence, only the oil shipped by pipeline is considered in this section. Of the 1.888 million horsepower depicted as the total horsepower developed in pumping stations, 1.43 million horsepower is developed from electrical power resulting in no environmental effects other than land use. The emissions due to the 0.31 million horsepower developed using diesel power can be determined by considering a specific fuel consumption of 0.38 pound fuel per brake horsepower-hour and assuming year-around operation which results in the conclusion that 144.9×10^6 gallons of fuel per year is used. If a 10 percent down-time is anticipated, 130.4×10^6 gallons of fuel per year is used.

Emission factors of 16 pounds of particulates per 10^3 gallons of fuel, 142 pounds of SO_2 per 10^3 gallons of fuel, 0.2 pound of CO per 10^3 gallons of fuel, 3 pounds of hydrocarbons per 10^3 gallons of fuel, and 80 pounds of NO_x per 10^3 gallons of fuel has been reported as appropriate for stationary units of the kind found in pumping stations.(I-15) Based on these data, Table I-7 shows the resulting emissions that have been calculated for the diesel operated pumping stations in crude oil pipelines.

TABLE I-7. EMISSIONS FROM DIESEL DRIVEN PUMPING STATIONS IN CRUDE OIL PIPE LINES

Pollutant	Emission, 10^3 tons/year
Particulate	1.09
SO_2	10.30
HC	0.22
NO_x	5.80
CO	0.14

Emissions from gas engines can be calculated in the same manner by assuming the gas engine to be as thermally efficient as the diesel engine and converting the specific fuel consumption into cubic feet of natural gas per brake horsepower hour. Accomplishing this requires a knowledge of the fuel heating value -- natural gas 1028 Btu/ft^3(I-27) and 18,300 Btu/lb of diesel fuel. The gas engine specific fuel consumption established in this basis is 6.76 cubic feet of fuel per horsepower hour. Emission data available from gas engines in pipelines are only available on the NO_x pollutant and are reported to be 7300lb NO_x per 10^6 cubic feet.(I-15) The emissions of NO_x as a result of 90 percent operation of a gas engine using 0.15 million horsepower in a crude oil pipeline is

$$[0.15 \times 10^6 \text{ hp}][24 \text{ hr/day}][365 \text{ days/year}][0.90][6.76 \frac{\text{ft}^3 \text{ fuel}}{\text{hp-hr}}][\frac{7300 \text{ lb } NO_x}{10^6 \text{ cu ft}}]$$

$$[\frac{\text{ton}}{2000 \text{ lb}}] = 29.179 \times 10^3 \text{ tons of } NO_x\text{/year.}$$

The transportation accident potential of transporting oil is significantly reduced as compared with coal since the primary mode of carrying oil is a pipeline. As a consequence, oil spillage and the pumping station represent the major emissions.

Spillage of oil usually occurs in rather concentrated areas around the loading and unloading area resulting in heavy saturation at the ground in specific areas. Heavy rainfall or perhaps a rise in the water table can result in significant water pollution from these saturated areas. Materials are currently available which can be utilized to decompose the oils in the area. Obtaining good results with this method requires a knowledge of the soils present and the type and density of the materials spilled. If at all possible, water-oil separators should be used in conjunction with a retention pond to prevent water pollution in the loading and unloading areas.

Projections of Emission. Figure I-5 illustrates the percentage of total crude oil transported by the various means has remained relatively constant over the past few years, and it is assumed that this relationship between the transport modes will be maintained. As a consequence, the pollution from oil transport over the future years is assumed to be in direct proportion to the percent increase of the crude oil demand required for electrical power generation. Table I-8 summarizes the estimates of the physical emission calculations from the transport of both coal and oil based on the assumptions as outlined above.

Pollution Controls

Coal and oil is basically transported by heavy duty diesel engines. Reference I-28 includes regulatory data on heavy duty engines but is restricted only to regulations through 1974. Smoke emissions and limited data on exhaust gaseous emission standards are presented. Smoke standards

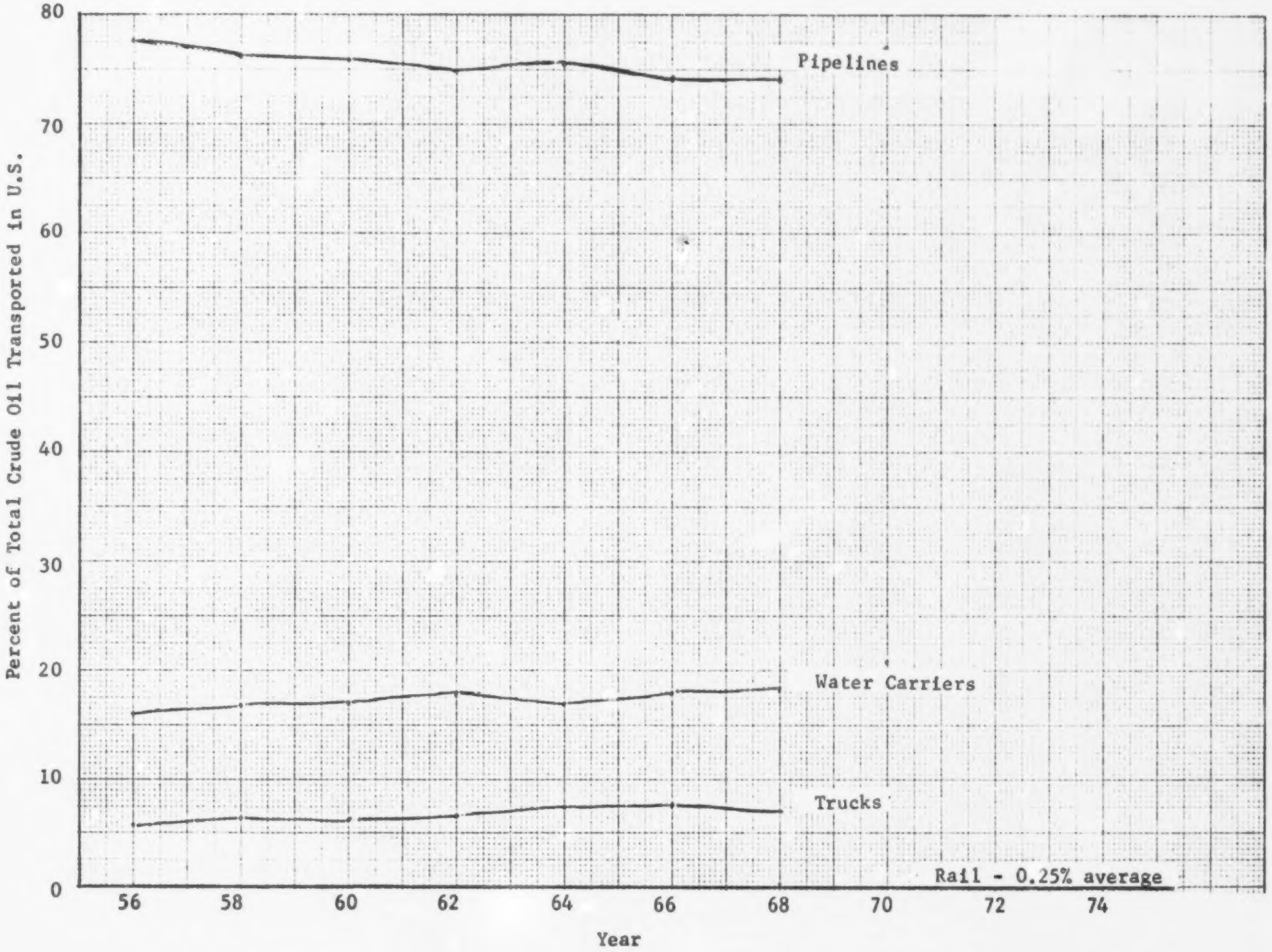

FIGURE I-5. RELATION OF TRANSPORT MODES IN CRUDE OIL TRANSPORT

TABLE I-8. PROJECTED EMISSIONS FROM TRANSPORT OF OIL FOR ELECTRICAL PRODUCTION

Method of Transport	Pollutant	1972	Emissions (10^3 Tons/Year)					
			1975	1980	1985	1990	1995	2000
Pipeline								
Diesel Engine	Particles	1.09	1.29	1.52	1.62	1.67	1.74	1.805
	NO_x	5.8	6.8	8.04	8.6	8.9	9.2	9.5
	CO	0.14	0.17	0.201	0.214	0.22	0.23	0.24
	SO_2	10.30	12.2	14.4	15.3	16.0	16.7	17.3
	HC	0.22	0.26	0.31	0.33	0.35	0.36	0.37
Gas Engine	NO_x	29.2	34.6	40.9	43.9	46.0	48.0	49.8

are established at opacity levels of 20 percent during the engine acceleration mode, 15 percent during the engine lugging mode, and 50 percent during the peaks in either mode. Exhaust emissions of 16 grams/brake horsepower of the hydrocarbons plus oxides of nitrogen and 40 grams/brake horsepower for carbon monoxide. In addition, regulatory action is being considered which would impose (1) a requirement of recording equipment on stacks exceeding a certain CFM threshold, (2) limitations regarding odor regulations, and (3) limitations of idle duration. Since the regulations currently imposed are only in effect until 1975 and the extent of regulatory measures to be imposed after 1975 is not evident, the projection of controls after 1975 and the corresponding costs of imposing these rules were not calculated.

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APPENDIX J

ELECTRICAL TRANSMISSION

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APPENDIX J

ELECTRICAL TRANSMISSION

Introduction

There are at present close to 4000 electric utility companies in the United States which operate over 400,000 miles of overhead transmission lines and about 2000 miles of underground transmission cables. The transmission lines utilize approximately 4 million acres of land for right of way. This section discusses the impact of the transmission lines on the environment, and points out methods of reducing these impacts.

Early transmission lines consisted simply of wood poles, wood cross arms, and solid copper conductors. Voltage levels were as low as 6900 V. As the requirements for electrical power increased, transmission voltages increased. For some years, 230 kV was the highest voltage in general use. At the present time, voltages of 345, 500, and 765 kV are in use, with future planning on the next highest voltage levels of 1000 kV and 1500 kV. Some data on mileage and load capabilities for different voltage levels compiled by McCaw(J-1) are shown in Table J-1.

TABLE J-1. MILEAGE AND LOAD CAPACITY FOR VARIOUS TRANSMISSION VOLTAGE LEVELS

Voltage kV up to 1969	Mileage 136,000	Loading, MW
69	82,000	
115	77,000	100
138	47,000	120
161	17,000	
230	37,000	240
287	1,000	
345	9,000	580
500	4,000	1,280
765		2,700
1,300		6,500
TOTAL	410,000	

As the voltages get higher, insulators and conductors become bigger and heavier, and towers evolved into large steel or aluminum structures with two-pole designs. In the future we are likely to see development in the areas of tower designs and material of construction, underground transmission, and cryogenic cooling.

The transmission of electrical energy from the generating station to the load centers must be considered as an integral part of the electrical power system. Thus, in any study of environmental emission of energy systems, due consideration must be given to the electrical transmission.

Environmental Factors

There are essentially two effects on the environment from transmission lines. One is a visual or esthetic; that is, transmission towers, along with their associated cables, are not a pretty sight to most people. The other is the actual destruction of the environment in a physical manner due to the transmission lines.

Esthetic Aspects of Power Transmission

Although there are surely some poeple who would consider a transmission line with its long sweeping curves of wires and graceful towers as a pleasant sight and a triumph to man's technology, most would consider the line as an intrusion into the natural beauty of a particular scene or view.

In general, the esthetic aspect of a line can be minimized by proper placement of the transmission corridor and by thoughtful design of the towers and lines.

The following points are considered to have a deleterious effect on the esthetics of the environment.(J-2)

1. Transmission lines in heavily timbered areas, over steep slopes, proximity to main highways, through shelter belts, and scenic areas.

2. Crossings of roads at intersections or interchanges.

3. Crossings over open expanses of water and marshland especially near flight lanes utilized by birds and waterfowl.

4. Long views of lines perpendicular to highway, canyons, and belts

5. Crossing hills and other high points at their crests

6. Long right-of-way "tunnels" through forests and wooded areas.

Tower design and placement also has an esthetic impact from the following standpoint:

1. Color of towers

2. Use of guyed towers especially where visible

3. Use of two structures for two circuits rather than consolidation.

Controls. The most obvious control technique for eliminating the adverse visual effects of transmission lines is to utilize underground systems in lieu of overhead transmission.

From an economic standpoint, in order for underground transmission to assume a major role in electrical transmission, much is still required to be learned. At the present time, cables are being operated at up to 345 kV and in general an oil-paper insulation is used. The cost of running an underground line is approximately ten times that of an overhead line.

Another control technique would involve the avoidance of the situations which tends to be undesirable by using additional lengths of line. For example, instead of crossing a hill over the crest (which may be the most economic way), additional lines could possibly be installed to circumvent the hill. Wooded and scenic areas could be bypassed.

A third technique would involve the planting of trees to shield long stretches of transmission lines from view. A cost comparison to these three major control techniques is given in Table J-2. The following was assumed in developing the cost data:

Line length	100 miles
Load capacity	1000 MW
Annual charges	13% of capital(J-3)
Cost of overhead transmission	\$150,000/mile(J-4)
Tree cost	\$25/tree, 35 ft apart

TABLE J-2. COSTS TO IMPROVE ESTHETICS

Option	Capital Costs, \$/kw	Operations, mils/kwhr
1. Underground transmission (entire length)	135	2.0
2. Plant trees along 20 percent of route (both sides)	0.2	0.003
3. Add 20 percent length to avoid undesirable areas	3.0	0.04

From this table, it is seen that underground transmission for the entire route at the present time is very expensive. The cost of the generating station itself is about \$135/kw. Even if only 20 percent of the line were underground, the cost would be high.

In contrast, rerouting or the planting of trees is a reasonable control technique, and would certainly be much less costly.

Means of improving the esthetics of the towers themselves are mainly limited to design and material modifications. Some of the more recent trends in this area are:

1. Horizontal post insulators
2. Single pole construction without arms. However, single-pole lines exclusive of right-of-way costs about \$2500 per mile more than the same line supported on the wider H-frames.
3. Painting the towers to blend in with the surroundings.
4. Use of insulators with a sky-blue glaze color instead of the common brown ones.
5. See-through poles
6. Use of concrete poles.

Nonesthetic Factors

Apart from the esthetic factors described above, transmission lines can have a direct, often physically destructive impact on the environment. The following considerations can be mentioned in this regard.

Clearing and Construction. In order for a transmission line to be constructed, the right-of-way must be prepared adequately. High trees are cut down to prevent arcing from the lines, brush and bushes are usually cleared, the ground must be suitably prepared, and access roads to the line are built. Each of these activities results in some physical destruction of the environment.

Other aspects of this problem are:

1. Open burning of construction wastes, trees, branches, and brush
2. Soil erosion of right-of-way due to removal of natural vegetation cover

3. Oil spills from construction equipment

4. Damage to trees, stream channels, etc., from blasting operations.

Control of Nonesthetic Factors. In general, control of the above factors requires planning construction activities with environmental conservation in mind. Such factors include:

1. Minimize clearing, and restore those cleared areas back to their original state insofar as possible.

2. Use of helicopters for conductor stringing and bringing in materials

3. Construction during seasons of low wildlife occurrence

4. Replacement of topsoil

5. Transportation of material to be burned to an area of small fire risk and heat damage to natural vegetation.

Future Considerations

Transmission design and technology is at present undergoing much change. In the past, right-of-way was easily obtained, but now it is much more difficult and expensive. An environmentally conscious public is demanding preservation of the environment. Also, people are objecting to the proximity of power plants, which necessitates increasing distances of electric transmission lines.

Major effort is being put into (1) ultra-high voltage lines (>745 kV) and (2) underground transmission.

The use of higher voltages will enable a given line to carry a higher load, and avoid the necessity of multiple circuits or lines.

With regard to underground transmission, research is proceeding in several areas.

Compressed Gas Insulation.(J-5)

In this method, the wire carrying the power is suspended concentrically in a pipe. Compressed gas (SF_6 is the most likely candidate) fills the annular space between the wire and the pipe. The advantages of this system include good heat transfer, and very low dielectric loss.

Cryogenics

It is well known that as certain materials are cooled down, the electrical resistance decreases. For example, pure aluminum or copper will be from 50 to 2000 times more conductive at liquid hydrogen temperatures than at room temperatures. At temperatures from 4 to 10 K, certain materials lose their resistance entirely, a state known as superconductivity.

The development of cryogenic technology will enable power to be carried by relatively small wires and should result in a reconsideration of the feasibility of underground transmission systems. Figure J-1 shows a projection of various types of underground systems.(J-6)

Another new concept which has been proposed for underground transmission is the use of wave guides utilizing microwave transmission. The big advantage of this system is the elimination of conductors and insulation. The major problems with this system are large losses in wave guides of conventional size, and the need for efficient terminal conversion equipment.

In summary, it appears that, at present, the major effort toward control of the impact of electrical transmission should be careful design of the corridors, lines, and towers within the environmental constraints. Replanting, additional line sections to avoid adverse visual impacts, and care during construction can be used very effectively.

In the future, it appears that underground technology will be developed sufficiently to enable either replacement of some sections of the transmission line or of the entire line.

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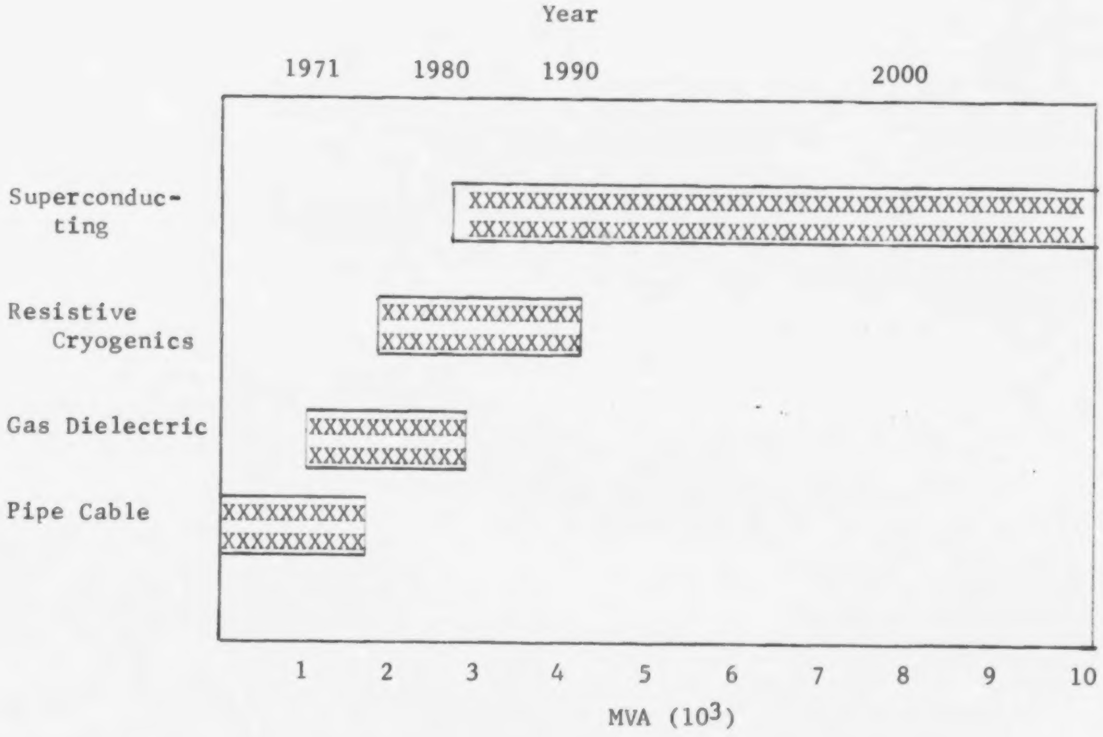

FIGURE J-1. CAPABILITIES OF UNDERGROUND TRANSMISSION

APPENDIX K

REMOVAL OF SULFUR FROM NATURAL GAS

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APPENDIX K

REMOVAL OF SULFUR FROM NATURAL GAS

Nature of the Problem

The sulfur content of natural gas is a function of the field from which the gas originates. Most of the sulfur present in natural gas is in the form of hydrogen sulfide. The hydrogen sulfide content may vary from near 0 to as high as 76 percent (as in Hinds County, Mississippi). The wide range of sulfur from typical natural gas is illustrated in Table K-1.

Hydrogen sulfide is a corrosive material, and therefore it is removed from natural gas before the gas is transported. Gas with a high sulfide content is called sour gas. Sweet gas is low in sulfur. Natural gas which is transported and sold in the United States has a hydrogen sulfide content of less than 0.25 grain per 100 standard cubic feet of methane.(K-1)

Sulfur Removal Technology

Sulfur is generally removed from natural gas by absorption in an alkaline solution. Ethanolamines are most commonly used, but other absorbents are also used in commercial practice. Carbon dioxide is also removed from the natural gas during this absorption step. The hydrogen sulfide is then desorbed and, when the sulfur content is high enough to warrant economic recovery of sulfur, is converted to elemental sulfur in a Claus sulfur plant. A generalized flowsheet of this sulfur extraction and recovery is shown in Figure K-1. The elemental sulfur is recovered from the converters in this process and is usually stored.

The oxidation of hydrogen sulfide to sulfur is exothermic, and it is believed that no fuel need be consumed in the process. In conventional operations, about 90 to 95 percent of the sulfur present in natural gas is recovered as elemental sulfur. The remainder is discharged to the air, primarily as sulfur dioxide, but also as other sulfur compounds.

When the sulfur content of natural gas is low, it is frequently uneconomic to recover sulfur. Under such conditions, hydrogen sulfide is frequently flared, and the resulting sulfur dioxide discharged directly to the atmosphere. For the purpose of this investigation, it has been assumed that this practice of direct discharge will not be permitted in future gas production. Therefore, this direct discharge of acid gases to the

TABLE K-1. COMPOSITION OF VARIOUS NATURAL GASES

	Composition, mole %, of gas from						
Component	Rio Arriba County, N.M.	Terrell County, Texas	Stanton County, Kansas	San Juan County, N.M.	Olds Field, Alberta, Canada	Lacq Field, France	Cliffside Field, Amarillo, Texas
methane	96.91	45.64	67.56	77.28	52.34	70.0	65.8
ethane	1.33	0.21	6.23	11.18	0.41	3.0	3.8
propane	0.19		3.18	5.83	0.14	1.4	1.7
butanes	0.05		1.42	2.34	0.16	0.6	0.8
pentanes and heavier	0.02		0.40	1.18	0.41		0.5
carbon dioxide	0.82	53.93	0.07	0.80	8.22	10.0	
hydrogen sulfide		0.01			35.79	15.0	
nitrogen	0.68	0.21	21.14	1.39	2.53		25.6
helium							1.8
total	100.00	100.00	100.00	100.00	100.00	100.00	100.00
total sulfur, grains/100 ft^3	0	6.3	0	0	22,525		
classification							
wet				x			
dry	x	x	x		x	x	x
sweet	x		x	x			x
sour		x			x	x	
gross heating value, Btu/ft^3	1,010	466	938	1,258	807	921	825
specific gravity	0.574	1.077	0.733	0.741	0.882	0.784	0.711

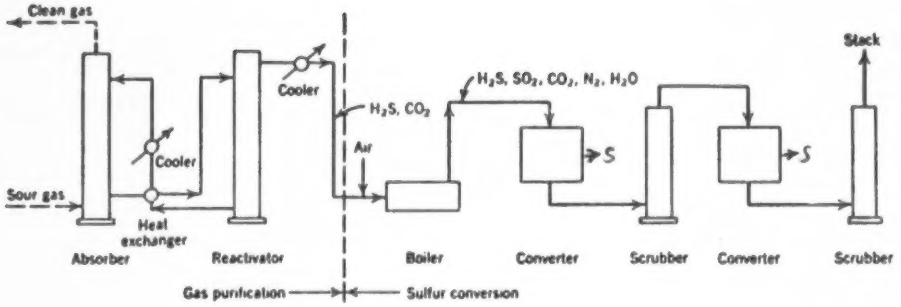
Clean gas
Sour gas
Cooler
Cooler
Heat exchanger
Absorber
Reactivator
H_2S, CO_2
Air
H_2S, SO_2, CO_2, N_2, H_2O
S
S
Stack
Boiler
Converter
Scrubber
Converter
Scrubber
Gas purification
Sulfur conversion

FIGURE K-1. PREPARATION OF SULFUR FROM HYDROGEN SULFIDE (GENERALIZED FLOWSHEET).

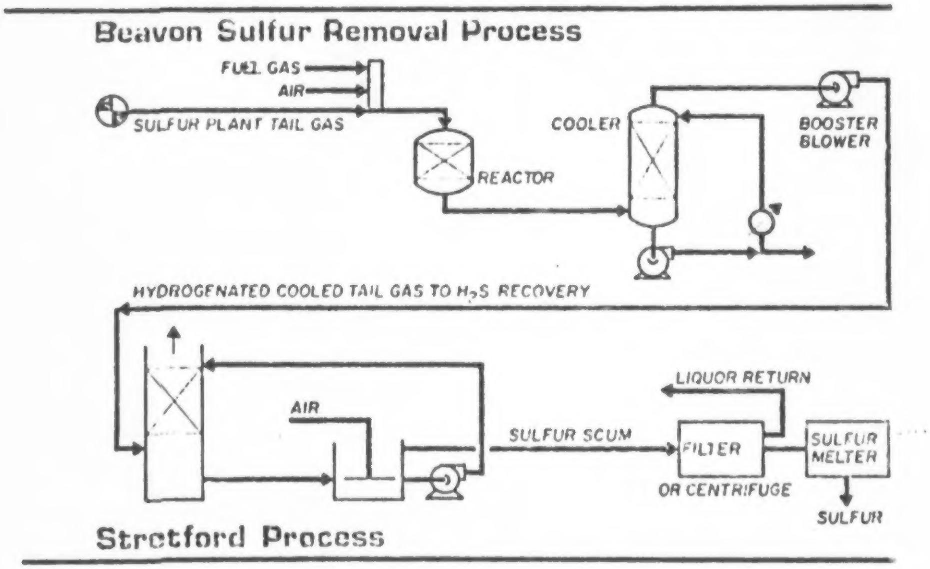
Beavon Sulfur Removal Process
FUEL GAS
AIR
SULFUR PLANT TAIL GAS
REACTOR
COOLER
BOOSTER BLOWER
HYDROGENATED COOLED TAIL GAS TO H_2S RECOVERY
AIR
SULFUR SCUM
LIQUOR RETURN
FILTER
OR CENTRIFUGE
SULFUR MELTER
SULFUR
Stretford Process

FIGURE K-2. FLOW DIAGRAM OF PROCESSES TO ELIMINATE AIR POLLUTANTS FROM TAIL GASES OF SULFUR PLANTS.

atmosphere has been ignored.

Sulfur Recovery Technology

As mentioned above, sulfur is currently removed from natural gas by absorption in an alkaline solution, followed by oxidation of the hydrogen sulfide to sulfur in a Claus plant. As currently practiced, this technology will result in removal of about 90 to 95 percent of the sulfur present in the natural gas.(K-2) In this investigation we have assumed that a new Claus plant would recover 95 percent of the sulfur present in natural gas. If the tail gas from the Claus sulfur plant is not treated, the remaining 5 percent of the sulfur will be vented to the atmosphere in the form of sulfur dioxide.

There are a number of new processes for the further removal of sulfur from the tail gas of a Claus sulfur plant. These include the Beavon,(K-2) the Shell,(K-3) and the Cleanair(K-4) processes. It has been claimed that 99.9 percent of the sulfur present in the gas can be recovered when these processes are used. This recovery is costly, however. The exact cost will depend upon the size of the plant, the quantity of sulfur in the tail gas, and the level to which the sulfur must be removed. In general, the investment for the Beavon process to remove additional sulfur will about equal the investment required for the Claus plant to achieve 90-95 percent sulfur recovery. For a sulfur plant with a capacity of about 100 long tons per day, the additional investment for the Beavon process would be between $700,000 and $1,000,000. In addition, the direct operating cost of the Beavon process (excluding depreciation and return on investment) will be about $25 per ton of sulfur recovered by the process.(K-5) This will add about $1.00-$1.30 per ton to the average cost of all sulfur recovered.(K-6)

For the purpose of this investigation, it has been assumed that the Beavon process or a similar process would be installed on new natural gas wells after 1975 and that these processes would recover 99.8 percent of the sulfur contained in natural gas.

Sulfur Emissions

It is difficult to estimate the emissions of sulfur dioxide from a natural gas processing facility because these emissions will be directly proportional to the sulfur content of the natural gas. It is assumed that before 1975 the emissions will be equivalent to 5 percent of the sulfur contained in natural gas, and that after 1975, technology will exist which will limit emissions to 0.2 percent of the sulfur present in natural gas.

Unfortunately, there is little data upon which to estimate the overall sulfur content of natural gas. The only data that were found during this investigation are summarized in Table K-2. These data were collected by Processes Research Inc.(K-7) These data represent about 9 percent of the natural gas produced in 1970. In addition, these data are biased toward high sulfur emissions because they were collected primarily in areas where sour gas is a significant factor. The Louisiana offshore gas has a relatively low sulfur content and the gas from the Alaskan North Slope has about an average sulfur content. Therefore, use of these data may tend to overstate the sulfur emissions.

As can be seen from Table K-2, the sulfur dioxide emitted as purged gas (i.e., from gas processing where there was no sulfur plant) greatly exceeds the sulfur oxide emissions as tail gas from the Claus sulfur plant. These emissions were ignored in making calculations. Furthermore, Processes Research assumed a 90 percent recovery of sulfur in the Claus plant, whereas we have assumed a 95 percent recovery. Assuming a 95 percent recovery of sulfur in the sulfur plant, and assuming the natural gas described in Table K-2 is representative, the emissions of sulfur dioxide would be 0.0183 pound per 1,000 cubic feet natural gas (Mcf). If one further assumes that the recovery technology after 1975 is the equivalent of 99.8 percent recovery of sulfur, the emission factor would be 0.00073 pound per Mcf.

Other Pollutants

Other than the emissions of sulfur oxides, emissions of other pollutants from natural gas sulfur recovery plants should be negligible. Small quantities of nitrogen oxide, carbon monoxide and hydrocarbons will be emitted by incineration of tail gas. Process pumps are driven by steam generated in the process.

There will no doubt be a small quantity of water pollutants resulting from condensate blowdown and possibly from treatment of process water. There may also be minor leaks of the alkaline absorbent. The emission of these pollutants is believed to be negligible. No data were found of these emissions.

Since the oxidation of hydrogen sulfide to sulfur is exothermic, there will be a certain amount of heat removed from the system. The quantity discharged to local waters would be highly dependent upon location and the individual processing characteristics. No estimate has been made of heat discharge to local streams.

No significant solid wastes are expected from the sulfur plant.

TABLE K-2. NATURAL GAS PROCESSED

	Gas Production		Sulfur			
State	State Total MM cf/d	Sour Gas MM cf/d	Sulfur Prodn. LT/D	Tail Gas SO_x T/D	Purged Gas SO_x T/D	Total SO_x T/D
1960						
Arkansas	177.1	177.1	99.0	70.4	255.8	326.2
Mississippi	244.5	--	--	--	--	--
New Mexico	2,183.5	1,176.5	41.6	12.0	862.9	874.9
North Dakota	41.0	41.0	45.4	7.6	--	7.6
Texas	13,638.9	2,158.3	428.6	102.5	566.5	669.0
Wyoming	369.0	111.0	385.5	102.8	212.4	315.2
	16,654.0	3,663.9	1,000.1	295.3	1,897.6	2,192.9
1970						
Arkansas	128.1	122.6	104.0	103.2	254.6	357.8
Mississippi	133.7	30.0	6.0	1.5	29.9	31.4
New Mexico	3,016.5	1,712.7	105.9	28.8	384.8	413.6
North Dakota	106.9	96.9	137.0	24.7	--	24.7
Texas	22,531.8	3,177.9	1,534.8	250.6	410.6	661.2
Wyoming	847.9	149.7	115.6	32.3	1,255.0	1,287.3
	26,764.9	5,289.8	2,003.3	441.1	2,334.9	2,776.0

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APPENDIX L

PETROLEUM REFINING

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APPENDIX L

PETROLEUM REFINING

Petroleum refineries, like people, are individualistic; no two are exactly alike. For the purposes of estimating emissions two vastly different types of refineries were considered. These are the conventional U.S. petroleum refinery, which is designed to maximize gasoline, and a topping refinery which is designed to maximize fuel oil.

Conventional U.S. Petroleum Refining

A modern petroleum refinery is a highly complex operation. Furthermore, each refinery has its own individual characteristics, its own blend of feedstocks, and its own special emissions problems. One may grasp the complexity of a typical petroleum refinery from the simplified flow diagram presented in Figure L-1. Because of the complexities and peculiar characteristics of each individual refinery, generalizations regarding refinery emissions will not be applicable to any given refinery. Nevertheless, such generalizations are useful for comparing the overall emissions of alternative energy sources on the environment.

Air Emissions

Although a 1966 publication by the National Academy of Sciences indicated that carbon monoxide was the principal atmospheric pollutant emitted from petroleum refineries,(L-1) most recent data indicate that sulfur dioxide and hydrocarbons are emitted in greatest quantity. Other major air pollutants from refinery operations are particulate matter and nitrogen oxides. There are also lesser emissions of aldehydes, organic acids, ammonia, and various other compounds which, although generally emitted in very low concentrations, contribute significantly to the odor near refineries. Emission data for the major air pollutants from some typical refineries in California are summarized in Table L-1. Because California refineries manufacture larger quantities of fuel oil than do their Eastern counterparts, these emission data may not be representative of the emissions from Gulf Coast refineries. Nevertheless, these data are believed to be sufficiently representative for the current investigation. The major sources of these pollutants are summarized in Table L-2.

Sulfur Oxides. **Catalytic Crackers. A major source of sulfur oxides from refineries is the regeneration of cracking catalysts. With fluid catalytic**

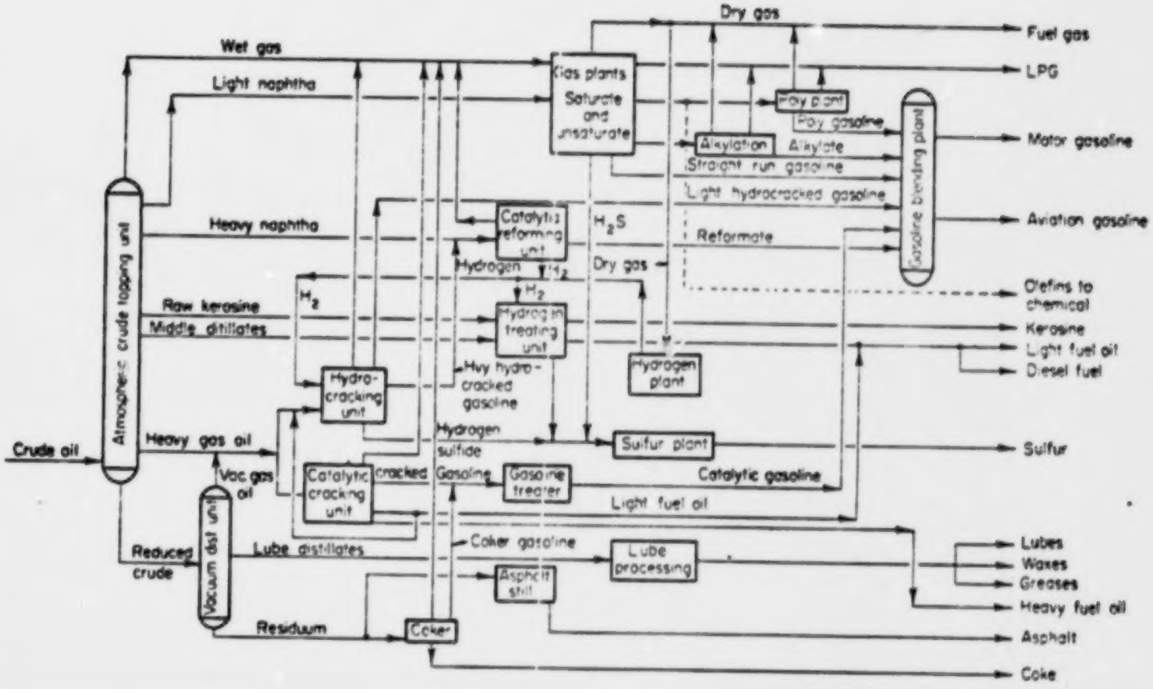

Crude oil
Atmospheric crude topping unit
Wet gas
Light naphtha
Heavy naphtha
Raw kerosine
Middle distillates
Heavy gas oil
Reduced crude
Vacuum dist unit
Vac gas oil
Lube distillates
Residuum
Gas plants Saturate and unsaturate
Dry gas
Poly plant
Poly gasoline
Alkylation
Alkylate
Straight run gasoline
Light hydrocracked gasoline
Reformate
Gasoline blending plant
Catalytic reforming unit
Hydrogen
H_2
H_2S
Dry gas
H_2
Hydrogen treating unit
Hydrogen plant
Hydro-cracking unit
Hvy hydro-cracked gasoline
Hydrogen sulfide
Catalytic cracking unit
cracked Gasoline
Gasoline treater
Catalytic gasoline
Light fuel oil
Sulfur plant
Coker gasoline
Lube processing
Asphalt still
Coker
Fuel gas
LPG
Motor gasoline
Aviation gasoline
Olefins to chemical
Kerosine
Light fuel oil
Diesel fuel
Sulfur
Lubes
Waxes
Greases
Heavy fuel oil
Asphalt
Coke

FIGURE L-1. PROCESSING PLAN FOR TYPICAL COMPLETE REFINERY

TABLE L-1. AIR EMISSIONS FROM CALIFORNIA REFINERIES

Refinery	Capacity[(a)] 1,000 Barrels per Calender Day	1970 Emissions[(b)] (pounds per day per 1,000 B/CD) Particulate	SO_2	Hydrocarbon	NO_x	CO
Standard Oil Co. of California Richmond Refinery	190	13	313	220	208	15
Union Oil Rodeo Refinery	60	13	343	187	93	--
Shell Oil Company Martinez	100	32	358	198	214	266
Phillips Petroleum Martinez	110	62	598	284	313	20
Los Angeles Area Refineries[(c)]	730	11	151	137	68	82

(a) Oil & Gas Journal, 69, 99 (March 22, 1971).

(b) Bay Area Air Pollution Control District, Source Inventory of Air Pollutant Emissions, San Francisco Bay Area, 1970.

(c) National Petroleum Council, Environmental Conservation, Vol. 2, p 183, (based on January 1969 publication).

TABLE L-2. POTENTIAL SOURCES OF SPECIFIC EMISSIONS FROM OIL REFINERIES

Emission	Potential Sources
Sulfur Compounds	Boilers, process heaters, catalytic-cracking unit regenerators, treating units, H_2S flares, decoking operations
Hydrocarbons	Loading facilities, turnarounds, sampling, storage tanks, waste water separators, blowdown systems, catalyst regenerators, pumps, valves, blind changing, cooling towers, vacuum jets, barometric condensers, air-blowing, high-pressure equipment handling volatile hydrocarbons, process heaters, boilers, compressor engines.
Oxides of Nitrogen	Process heaters, boilers, compressor engines, catalyst regenerators, flares
Particulate Matter	Catalyst regenerators, boilers, process heaters, decoking operations, incinerators
Aldehydes	Catalyst regenerators
Ammonia	Catalyst regenerators
Odors	Treating units (air-blowing, steam-blowing), drains, tank vents, barometric condenser sumps, waste water separators
Carbon Monoxide	Catalyst regeneration, decoking, compressor engines, incinerators

Source: U.S. Department of Health, Education and Welfare, Atmospheric Emission From Petroleum Refineries, A Guide for Measurement and Control, Publication No. 763 (HEW Public Health Service, 1960).

cracking units, the emission of sulfur dioxide is about 525 pounds per thousand barrels feed. With moving bed catalytic cracking units (TCC units) the emissions would be about 60 pounds per million barrels fresh feed.(L-2) If one assumes that new refineries will install fluid catalytic cracking units, as has been the recent trend, and that the ratio of catalytic cracking fresh feed to crude capacity remains at the January, 1972, ratio of 0.33, the emissions of sulfur dioxide from new cat crackers would be about 175 pounds per thousand barrels crude processed. Reference to Table L-1 will quickly indicate that cracking accounts for a significant fraction of the sulfur dioxide emissions.

Desulfurization. A 1966 study indicated that the average sulfur content of crude oil processed in U.S. refineries was 0.76 percent.(L-1) The same study indicated that 30 percent of the sulfur went into the products. Most of the rest of this sulfur is converted to hydrogen sulfide during refining operations. Technology exists, and is in fact used in many refineries, to recover this hydrogen sulfide by absorption and to convert the absorbed hydrogen sulfide to elemental sulfur. About 95 percent conversion of this hydrogen sulfide to sulfur is considered to be typical in a two-stage Claus sulfur plant.(L-3)

If one assumes that 70 percent of the sulfur entering a refinery will be converted to hydrogen sulfide and that 95 percent of this will be recovered as elemental sulfur, then the emissions of sulfur dioxide will be equivalent to 3.5 percent of the sulfur present in the crude. On this basis, the emissions of sulfur dioxide (in pounds per thousand barrels crude) would be 224 times the percent sulfur in crude oil. Applying this factor to the national crude sulfur average for 1966 of 0.76 percent sulfur, the emissions of sulfur dioxide expected would be 170 pounds per thousand barrels crude. When added to the 175 pounds expected from cat-cracking operations, one gets a total of 345 pounds sulfur dioxide per thousand barrels crude oil. This is in remarkable agreement with the emissions reported in Table L-1. (Assuming that low-sulfur gas rather than high-sulfur residual was the primary fuel in these refineries in the years for which data are available.)

With the addition of a process for removal of sulfur from the sulfur-plant tail gas, overall recovery efficiencies can be increased from 95 to about 99.8 percent. (Claims for the Beavon process are 99.9(L-4) percent removal, but although commercial units are currently under construction, none have yet been commercially demonstrated.) This would reduce the emission of sulfur dioxide (in pounds per thousand barrels crude run to stills) from this source to about 9 times the percent sulfur in the crude oil. The Beavon process or similar technology will probably be standard practice in new refineries by 1975.

Combustion. As can be seen from Table L-2, another significant source of sulfur oxides in a refinery is combustion of fuel. Obviously, the quantity of sulfur dioxide emitted depends upon the concentration of sulfur oxides from the flue gas. Many of the process heaters used in a refinery have heat inputs of less than 250 million Btu per hour, and are therefore exempt from the Federal emission regulations currently in effect. Fortunately, a major fraction of the refinery fuel is natural gas or refinery gas from which sulfur can be readily removed. In 1969, U.S. refineries consumed 998 billion cubic feet of natural gas. This natural gas accounted for approximately 36 percent of the total refinery energy input. In addition, 985 billion cubic feet of refinery gas was burned. Coke and residual oil each accounted for about 10 to 11 percent of refinery energy input in 1969. If future refineries are located at sites other than the Gulf Coast, or if natural gas is not available to future Gulf Coast refineries, one can expect the use of fuel oil with higher sulfur contents to increase.

Refinery energy consumption in the 1965 to 1969 period averaged 704,000 Btu per barrel crude oil.(L-5) Of this about 3 percent was purchased electricity or steam, leaving an average of about 680,000 Btu per barrel. If fuel oil with the maximum sulfur content meeting the Federal emission regulations of 0.8 pound sulfur dioxide per million Btu were consumed at the average fuel rate, a typical refinery would emit 540 pounds sulfur dioxide per thousand barrels crude run to stills.

In a typical new refinery where natural gas is unavailable, about 35 percent of the energy requirements might be obtained from refinery gas, the rest from fuel oil. Again assuming emissions from the fuel oil to be 0.8 pound sulfur dioxide per million Btu, the average refinery emissions would be about 350 pounds sulfur dioxide per 1,000 barrels crude oil processed. The actual emissions are more likely to be controlled by state rather than Federal limits, however, because many process heaters have heat inputs of less than 250 million Btu per hour and are therefore exempt from Federal regulations. Nevertheless, the assumption of the Federal sulfur dioxide limitations is believed to provide a sufficiently accurate estimate of maximum emissions for the purposes of this investigation.

Overall Sulfur Oxide Emissions. The average sulfur content of crude processed by U.S. refineries in 1966 was 0.76 percent.(L-1) Since imports (mostly Canadian and Venezuelan) accounted for only 13 percent of crude runs to stills in 1966,(L-6) this is representative of domestic production. Since it appears likely that the United States will become increasingly dependent on Eastern Hemisphere crude oil, it is important to recognize the impact that these new crude sources will have on the environment. Because many of the refinery emissions of sulfur oxides depend upon the sulfur content of the crude oil processed, a number of cases must be considered. The cases considered and average sulfur content are summarized in Table L-3. It should be recognized that these are typical sulfur analyses, but that the sulfur contents of crudes from any location will vary.

The fuel consumed at the refinery is also an important consideration. It is likely that natural gas would be consumed at a new Gulf Coast refinery but that residual oil and refinery gases would fuel a refinery at other locations. The sulfur content of this residual oil would

TABLE L-3. ESTIMATED REFINERY SULFUR DIOXIDE EMISSIONS

Refinery Fuel	Crude Source	Crude Gravity, °API	Sulfur Content, %	SO_2 Emissions, lb/1000 bbl	
				Pre-1975	Post-1975
Natural gas	Nigeria (Delta)	31.0	0.18	54	43
	1966 mix		0.76	345	183
	Alaska (Prudhoe Bay)	27.0	0.86	383	207
	Venezuela (Tia Juana)	27.0	1.5	680	360
	Saudi Arabian mix	34.9	1.63	740	392
	Kuwait	31.4	2.5	1,140	600
Residual (0.75% S)	Nigeria (Delta)			404	393
	1966 mix			695	533
	Alaska (Prudhoe Bay)			733	557
	Venezuela (Tia Juana)			1,030	710
	Saudi Arabian mix			1,090	742
	Kuwait			1,490	950
Residual (2.3 x Crude %S)	Nigeria (Delta)			248	237
	1966 mix			1,261	999
	Alaska			1,308	1,132
	Venezuela			2,290	1,970
	Saudi Arabian mix			2,490	2,142
	Kuwait			3,820	3,280

probably be a function of location. For illustration, residual oils with sulfur contents of 0.73 percent and 2.3 times the percent sulfur in the crude were chosen. The former level corresponds to the Federal emission standard for liquid fuel while the latter approximates the sulfur content of residual oil without desulfurization.

Nitrogen Oxides. The major source of nitrogen oxides in refineries is in combustion operations. Refineries contribute a relatively small proportion of the national nitrogen oxide emissions. An extensive study of 1968 emissions in the Los Angeles area, which has a large concentration of refineries, indicates that the nitrogen oxide emissions from refineries represented about 2.6 percent of total nitrogen oxide emissions for the area.(L-1) The weighted percent of nitrogen oxide emissions from Table L-1 is 126 pounds per thousand barrels crude processed applying standard emission factors only to the fuel oil, natural gas and refinery gas consumed at refineries in 1969, one obtains a value of 138 pounds per thousand barrels. This ignores minor contributions from burning of coal, coke, and other fuels in refineries. Based on these simple calculations, it appears that a typical value for nitrogen oxide emissions from refineries would be about 130 pounds per thousand barrels crude processed.

Particulate Emissions. The major potential source of particulate emissions from a refinery is the catalyst fines from catalytic cracking. Lesser sources of particulate emissions are combustion, and possibly coking operations. The standard emission factor for catalyst of particulates from fluid catalytic cracking units is 61 pounds per thousand barrels fresh feed.(L-2) This would be the equivalent of about 20 pounds per thousand barrels crude. Most refineries use two-stage conventional cyclones to recover catalyst fines, and many also use an electrostatic precipitator to treat the flue gas from catalyst regenerators before it is discharged to the atmosphere. Based on the data in Table L-1, it is believed that particulate emissions of about 12 pounds per thousand barrels crude represent good refinery practice.

Carbon Monoxide. The only significant source of carbon monoxide emissions in the petroleum refinery is the catalytic cracking catalyst regenerator. Carbon monoxide emissions from these units can be eliminated by incinerating the gases in waste heat boilers. In addition to oxidizing carbon monoxide to carbon dioxide, traces of aldehydes, hydrocarbons, and cyanides are also destroyed by this incineration. Refinery emissions of carbon monoxide are trivial when compared with automotive and other sources. For this investigation, it is assumed that carbon monoxide emissions will amount to 15 pounds per thousand barrels crude processed when carbon monoxide boilers are used.

Hydrocarbons. Hydrocarbon emissions in petroleum refineries generally originate from storage tanks, loading and transfer facilities, and accicental spills and leaks. Hydrocarbon emissions from petroleum refineries may range from 0.1 to 0.6 weight percent of the crude oil processed according to a 1969 report by the U.S. Department of Health, Education and Welfare.(L-7) The equivalent of 0.1 weight percent is about 345 pounds hydrocarbon emissions per thousand barrels. The data in Table L-1 indicate that California refineries have considerably lower emissions and probably represent the best control technology available. Based on data from these refineries, an emission factor of 140 pounds hydrocarbon per 1,000 barrels crude oil is assumed.

Odors. There are a number of malodorous compounds associated with petroleum refining which can be detected by the human nose at extremely low concentrations. These compounds are generally sulfides, amines, aldehydes, and phenols. Many can be detected at concentrations of one part per billion or less. Incineration of gases containing these malodorous compounds will generally eliminate them. The various smells and odors around a refinery represent a nuisance rather than a hazard and can be regarded as having a small, although very noticeable, impact on the environment.

Water Pollution

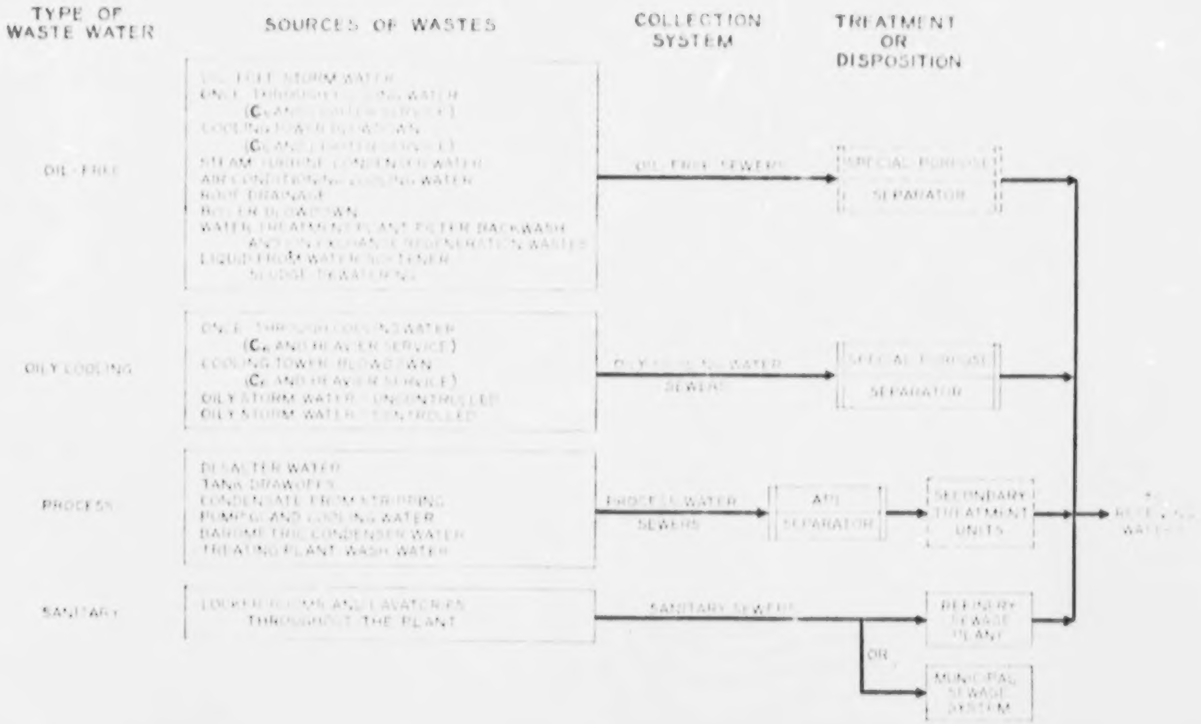
The major sources of aqueous effluents from refineries are summarized in Figure L-2.

These effluent waters from a petroleum refinery may contain many foreign substances, including dissolved and suspended organic compounds, suspended solids, dissolved salts, acids, and alkalis. The organic compounds in refinery effluent consist primarily of oil, but also include phenolic compounds, aldehydes, ketones, amines, and other organic compounds.

The usual measures of the organic content of water are the biological oxygen demand (BOD) and chemical oxygen demand (COD). BOD is the quantity of oxygen utilized by microorganisms to stabilize the waste in a specified period of time. COD is the quantity of oxygen needed to chemically oxidize the effluent water. All organic compounds normally found in the effluent water contribute to COD and most contribute to BOD.

Typical refinery effluent figures for the major contaminants in aqueous effluents are summarized in Table L-4. These data were obtained in 1967. The results of a new survey currently under way should be available by early 1973. Preliminary results of the new survey were not released for inclusion in this study.

The refineries surveyed to obtain the data in Table L-4 represented 86.5 percent of the U.S. refinery capacity. Atypical refining capacity like asphalt plants, lube oil blending plants, and specialty plants were specifically excluded from the tabulation. The refinery classifications and percentage of U.S. refining capacity are:


TYPE OF WASTE WATER
SOURCES OF WASTES
COLLECTION SYSTEM
TREATMENT OR DISPOSITION
OIL-FREE
OIL-FREE STORM WATER
ONCE-THROUGH COOLING WATER
(C_3 AND LIGHTER SERVICE)
COOLING TOWER BLOWDOWN
(C_3 AND LIGHTER SERVICE)
STEAM TURBINE CONDENSER WATER
AIR CONDITIONING COOLING WATER
ROOF DRAINAGE
BOILER BLOWDOWN
WATER TREATMENT PLANT FILTER BACKWASH
AND ION EXCHANGE REGENERATION WASTES
LIQUID FROM WATER SOFTENER
SLUDGE DEWATERING
OIL-FREE SEWERS
SPECIAL PURPOSE SEPARATOR
OILY COOLING
ONCE-THROUGH COOLING WATER
(C_4 AND HEAVIER SERVICE)
COOLING TOWER BLOWDOWN
(C_4 AND HEAVIER SERVICE)
OILY STORM WATER (UNCONTROLLED)
OILY STORM WATER (CONTROLLED)
OILY COOLING WATER SEWERS
SPECIAL PURPOSE SEPARATOR
PROCESS
DESALTER WATER
TANK DRAWOFFS
CONDENSATE FROM STRIPPING
PUMP GLAND COOLING WATER
BAROMETRIC CONDENSER WATER
TREATING PLANT WASH WATER
PROCESS WATER SEWERS
API SEPARATOR
SECONDARY TREATMENT UNITS
TO RECEIVING WATERS
SANITARY
LOCKER ROOMS AND LAVATORIES
THROUGHOUT THE PLANT
SANITARY SEWERS
REFINERY SEWAGE PLANT
OR
MUNICIPAL SEWAGE SYSTEM

Source: American Petroleum Institute Manual on Disposal of Refinery Wastes, p 3-5, (1969).

FIGURE L-2. EXAMPLE OF A PLAN FOR THE COLLECTION AND TREATMENT OF REFINERY LIQUID WASTES

TABLE L-4. SUMMARY OF EFFLUENT DATA

	Pounds Per Day Per Thousand Barrels Crude Oil Throughput																			
	TYPE OF EFFLUENT TREATMENT																			
	Primary					Intermediate					Biological					Total Refineries Reporting				
	Refinery Classification					Refinery Classification					Refinery Classification					Refinery Classification				
	A	B	C	D	E	A	B	C	D	E	A	B	C	D	E	A	B	C	D	E
	Lbs/D/MBD																			
BOD																				
Maximum	87.6	208.9	350.0	297.8	143.8		26.7	82.9		96.6		338.3	60.8	235.4	168.4	87.6	338.3	350.0	297.8	168.4
Minimum	5.8	0.2	5.4	37.0	92.6		25.6	13.9		75.6		0.2	2.6	5.5	65.2	5.8	0.2	2.6	5.5	65.2
Average (Arith)	30.5	70.7	116.5	122.5	118.2		27.2	42.5		86.1		27.2	33.0	67.4	115.5	30.5	33.3	67.6	86.2	108.8
Average (Weighted)	56.2	73.8	141.1	146.9	125.1		27.2	43.4		88.8		26.2	33.9	67.6	107.7	30.7	36.5	[illegible]	118.6	107.6
COD																				
Maximum		944.8	836.0	1401.5	366.0		79.0	144.1		395.3		600.0	209.0	649.4	1054.8	1508.9	600.0	[illegible]	1401.5	1054.8
Minimum		12.3	10.8	77.4	152.8		61.9	56.0		155.9		4.8	26.9	26.3	256.3	9.0	4.8	10.8	26.3	152.8
Average (Arith)		168.6	123.7	300.7	259.1		97.4	99.5		275.6		95.4	97.0	167.7	673.5	769.0	114.3	108.3	270.4	471.4
Average (Weighted)		207.1	116.9	216.3	287.9		98.5	109.1		245.0		77.8	96.5	159.1	706.4	535.1	120.7	107.2	175.0	566.1
Oil																				
Maximum	86.2	154.3	290.0	277.2	88.2	5.5	6.3	52.7		81.6		64.0	37.8	163.4	131.6	86.2	154.3	290.0	277.2	131.6
Minimum	0.6	0.6	1.0	4.5	6.8	0.8	0.5	1.8		7.6		0.1	3.7	0.4	29.3	0.6	0.1	1.8	0.4	6.8
Average (Arith)	16.4	33.4	36.6	53.2	47.5	2.7	4.4	12.6		14.6		5.6	15.4	27.9	69.9	13.0	16.0	31.6	38.7	50.4
Average (Weighted)	29.0	25.4	46.6	67.5	58.5	1.2	5.1	17.2		16.4		5.6	16.1	26.5	71.9	18.0	11.7	27.6	50.9	68.3
Phenols																				
Maximum	3.5	99.2	5.6	44.4	9.5	1.1	2.1	81.6			0.5	8.6	7.0	13.3	10.9	3.5	99.2	81.6	44.4	10.9
Minimum	*	0.1	0.6	1.2	1.6	0.01	0.2	0.3			0.04	*	*	0.01	1.6	*	*	*	0.01	1.6
Average (Arith)	0.9	11.4	2.6	7.4	5.6	0.6	1.1	7.5			0.3	1.0	1.8	2.9	6.2	0.7	3.8	3.9	5.0	6.0
Average (Weighted)	0.8	13.4	2.4	10.2	6.6	0.9	1.3	6.6			0.5	0.9	1.9	3.9	6.3	0.8	4.1	3.7	8.2	6.3
Suspended Solids																				
Maximum	101.1	365.7	350.0	113.0	98.1	195.0	15.7	56.3				154.5	16.3	72.2	190.0	195.0	365.7	350.0	113.0	190.0
Minimum	0.8	*	10.0	0.1	33.7	2.1	10.5	0.1				1.3	3.0	4.0	87.0	0.8	*	0.1	0.1	7.8
Average (Arith)	26.0	71.8	70.8	38.3	63.9	78.6	13.1	18.4				26.2	11.7	25.3	117.1	43.5	38.3	39.7	31.8	97.1
Average (Weighted)	56.6	85.3	48.1	40.7	79.0	12.3	13.1	20.6				20.7	17.8	26.5	118.7	33.1	37.3	27.0	35.5	103.8
Dissolved Solids																				
Maximum	13600.0	2687.5	7600.0	1157.4	350.0	50.4		958.0				4800.0	516.7	543.9		13600.0	4800.0	7600.0	1157.4	6806.5
Minimum	56.8	14.7	83.0	241.9	78.4	36.7		529.4				4.5	307.7	257.7		56.7	4.5	83.0	241.9	78.4
Average (Arith)	2511.4	604.7	1667.1	558.2	214.2	43.6		703.8				527.5	412.2	371.8		1691.0	541.2	1127.0	489.0	2006.8
Average (Weighted)	4966.7	465.5	1063.6	576.9	177.6	47.8		780.2				366.1	855.9	317.3		2695.1	408.7	855.9	483.6	3097.3
Alkalinity																				
Maximum	101.1	463.5	41.7	58.1	220.3	9.8		71.1		109.8		736.7	87.2		154.7	101.1	736.7	87.2	58.1	220.3
Minimum	6.6	2.5	40.9	45.7	65.8	3.3		1.4		93.0		0.3	14.1		70.6	3.3	0.3	1.4	34.6	65.8
Average (Arith)	53.9	109.1	41.3	51.9	143.1	6.6		42.4		101.1		125.1	44.3		112.7	30.2	117.0	42.8	44.3	118.9
Average (Weighted)	73.0	107.8	41.2	48.3	163.9	9.1		48.2		103.8		90.1	40.8		120.2	36.7	80.8	43.8	41.8	120.9
Sulfide																				
Maximum	0.9	41.9	7.5	127.7				10.7				26.7	9.1	4.3	6.7	0.9	41.9	10.7	127.7	6.7
Minimum	0.1	0.03	2.0	0.7				1.1				0.08	0.6	0.1	1.0	0.01	0.03	0.6	0.1	0.3
Average (Arith)	0.4	11.3	5.0	26.4				6.5				2.0	3.2	2.2	2.9	0.3	5.2	4.7	18.1	2.1
Average (Weighted)	0.6	5.6	4.4	41.9				5.5				1.7	1.9	1.0	3.1	0.5	2.7	3.7	36.8	2.8
F																				
Maximum		1.1		1.5								8.2	1.9	1.0			8.2	1.9	1.5	9.7
Minimum		0.1		0.2								0.01	0.2	0.2			0.01	0.2	0.2	0.3
Average (Arith)		0.5		0.9								1.9	1.1	0.5			1.5	1.1	0.7	1.5
Average (Weighted)		0.5		1.0								2.3	1.0	0.4			1.8	1.0	0.8	6.3
NH_3(N)																				
Maximum		199.0	33.6	27.8			2.6					48.0	7.0	69.7			199.0	33.6	69.7	21.7
Minimum		3.8	3.6	4.8			1.2					0.03	2.1	2.7			0.03	2.1	2.7	3.9
Average (Arith)		29.8	19.6	16.1			1.9					9.7	3.9	22.0			19.1	9.1	18.2	13.7
Average (Weighted)		26.8	24.9	17.6			1.7					10.0	3.6	32.1			27.0	11.9	23.8	16.5
Total Refineries Reporting	2	23	8	2	2	5	5	6	1	2	2	43	6	8	2	13	72	20	18	9

Source: American Petroleum Institute, 1967 Domestic Refinery Effldent Profile (Sept, 1968).

		Percent
A	Topping plants	3
B	Topping and cracking	28
C	Topping, cracking, and petrochemical	19
D	Integrated (topping, cracking, and lube processing)	20.5
E	Integrated and petrochemical	16

The types of waste water treatment described in Table L-4 are primary, intermediate, and biological. Of the refinery capacity included in the survey, 38 percent used primary, 13 percent intermediate, and 49 percent biological treatment. Primary treatment is gravity separation only. This is accomplished in API separators or similar equipment. Intermediate treatment includes chemical flocculation, air flotation with or without chemical addition, or filtration. Biological treatment includes activated sludge, trickling filter, stabilization ponds with and without aerators, and biological oxidation in cooling towers.

The arithmetic average referred to in Table L-4 is the average of the refineries reporting, while the weighted average is the average of the crude oil throughout. The weighted average will be closer to practice in larger, newer refineries, although the differences between the arithmetic and weighted averages are probably not significant.

For the purposes of estimating effluents from future conventional refineries, the data in Table L-4 on refinery categories B, C, D, and E were combined on a judgmental basis. Category B would be most representative, but it includes many smaller, older refineries. C and E include petrochemicals which are excluded from this analysis. D and E include lube oil processing which will be included in some but not all new refineries. New refineries will probably be equipped with biological or intermediate waste water treatment systems. The estimated water pollutants from new refineries are summarized in Table L-5. These estimates are highly subjective and should be replaced when better data become available.

Solid Wastes

There are three types of waste which comprise most of the solid wastes from a petroleum refinery. These are sludges containing water and solids; sludges containing oil, water, and solids; and biological solids. There is also the usual trash, paper, etc., associated with most businesses.

The sludges containing water and solids but no hydrocarbons generally come from raw-water treatment. The quantities of these solids depend almost entirely upon the quality and quantity of raw water used by the refinery. These solids are generally recovered in settling ponds, or by filtration or centrifugation. They will generally be disposed of eventually in landfill. Another source of solids which do not contain oil are catalyst fines. As the particulate emission standards are enforced, the spent catalyst fines will represent an increasing source of solid waste. Again landfill will be the ultimate disposal method. The fines obtained in the manufacture of petroleum coke are usually disposed of by percolating a slurry of these fines through the coke car. The fines are filtered out in this percolation.

TABLE L-5. ESTIMATED AQUEOUS EFFLUENTS FROM NEW REFINERIES

	Pounds per Day per Thousand Barrels per Day
BOD	30
COD	110
Oil	8
Phenols	2
Suspended solids	20
Dissolved solids	500
Alkalinity	nil
Sulfide	2.5
Phosphorus	1
Nitrogen	4

Sludges that contain oil in addition to water and solids present the most difficult solid waste disposal problems at a refinery. These sludges are obtained primarily from API separators and consist of water, iron oxides and sulfides, sand, silt, and clay obtained from the crude oil. Tank bottom sludges, and sludges from biological treatment processes are additional sources of these solid wastes. These sludges are frequently dewatered by centrifugation or filtration and then either incinerated or spread thinly over vacant land at the refinery site to enable decomposition by soil bacteria.

Biological solids are produced by most biological processes. The quantities of excess biological solids from biological treatment processes depend upon the operation of the process.

Little useful quantitative data on the amount of solids which must be disposed of from a typical refining operation were obtained during this investigation. Some data on solid wastes collected by the State of Pennsylvania were reviewed, but the quantities appeared to contain mostly water and were not, therefore, considered useful. It is believed that the State of California has also surveyed solid wastes emissions from petroleum refining, but these data were not available for our review during this investigation.

Data on typical sludge volumes from one 42,000 barrel-per-day refinery were obtained, however. These volumes would be 700 to 1000 cubic yards per year. This is equivalent to 0.061 to 0.087 cubic yard per 1000 barrels crude run to stills.(L-8) The quantities of solid wastes will be greatly influenced by the refinery location and by the degree of enforcement of air and water emission regulations. One generalization which can be made: as the air and water emission regulations become increasingly more restrictive, the solid waste disposal problem due to increased treatment will increase. A value of 0.08 cubic yard sludge per 1000 barrels was taken as typical for the purposes of this study.

Energy Requirements and Thermal Emissions

In the five years, 1965 through 1969, U.S. refineries consumed an average of 704,000 Btu per barrel crude oil run to stills.(L-5) This energy consumption will have an impact in that it is energy not available for other uses. Furthermore, this energy consumption is, for the most part, rejected to the environment in the form of heat. This heat escapes as flue gas, heated water, and as radiation to the atmosphere. Such rejected heat does not necessarily constitute a form of pollution, however. In many instances it may even provide beneficial effects on the environment. Nevertheless this energy requirement and heat rejection is a factor which should be considered in any thorough analysis. A breakdown of refinery fuel consumption by type of fuel is given in Table L-6.

Noise

There is a certain amount of noise associated with normal refinery operations. Since most U.S. refineries are located far from residential areas, however, this noise does not generally present a problem. Refiners like many other industrialists recognize that excessive noise can present problems and generally strive to obtain the quiet operation in new facilities when this can be achieved at low cost. In this investigation noise from refinery operations is considered to have a negligible impact on the environment.

Land Use

A modern petroleum refinery requires a large area. Most of this land is needed for tank farms to store crude oil and products. Relatively little land by comparison is used for the process facilities. An increasing amount of land will be needed for pollution control, e.g., settling ponds, water treatment plants, disposal sites for oily sludge, etc. In addition, there is usually a buffer zone at least 500 feet wide surrounding the entire refinery.

It is very difficult to generalize on the land requirements for a new grass roots refinery because each site represents a special situation.

TABLE L-6. FUELS CONSUMED AT U.S. REFINERIES, 1925-1969

Year	Fuel Oil[1] (Thousands of Barrels)	Acid Sludge (Thousands of Barrels)	Coal (Thousands of Short Tons)	Natural Gas (Millions of Cubic Feet)	Refinery Gas (Millions of Cubic Feet)	Petroleum Coke[2] (Thousands of Short Tons)	Purchased Electricity (Thousands of Kilowatt Hours)	Liquefied Petroleum Gas (Thousands of Barrels)	Purchased Steam (Millions of Pounds)	Total Btu Equivalent[3] (Billions)	Crude Oil Run to Stills (Thousands of Barrels)	Btu per Barrel of Crude Oil Run to Stills	Year
1969	43,323	95	570	927,886	984,561	10,625	17,927,000	6,620	24,396	2,729,174	3,880,998	703,000	1969
1968	41,963	102	739	973,937	921,850	10,545	16,369,000	5,506	22,211	2,534,420	3,774,369	675,000	1968
1967	39,626	237	859	936,085	838,529	10,442	15,106,000	3,043	23,318	2,470,657	3,582,594	672,000	1967
1966	37,523	201	983	897,105	842,325	10,498	12,549,000	2,210	19,379	2,419,070	3,447,193	701,000	1966
1965	36,650	192	912	857,839	843,072	10,569	12,787,000	3,649	17,026	2,331,426	3,300,942	725,000	1965
1964	37,649	256	814	825,473	830,415	10,673	12,672,000	10,455	20,257	2,345,649	3,223,329	733,000	1964
1963	43,792	303	753	789,951	785,505	9,493	12,046,000	8,499	20,301	2,271,545	3,172,652	716,000	1963
1962	41,713	360	736	789,977	767,069	10,263	11,429,000	5,502	18,749	2,256,225	3,089,531	738,000	1962
1961	40,912	533	714	772,028	766,615	10,049	11,243,000	4,009	17,297	2,226,355	2,987,138	745,000	1961
1960	41,212	881	742	775,154	752,881	9,206	10,357,000	3,679	17,863	2,196,549	2,952,534	744,000	1960
1959	41,853	895	951	752,239	743,052	5,354	9,355,000	3,249	17,694	2,075,449	2,917,661	711,000	1959
1958	43,651	1,101	1,027	681,354	715,152	4,498	8,632,000	3,695	18,837	1,975,973	2,776,096	712,000	1958
1957[4]	39,613	1,525	939	682,270	694,668	4,101	8,605,570	4,209	13,838	2,225,346	2,890,435	770,000	1957[4]
1956	37,935	1,934	1,067	679,343	653,699	2,671	6,917,823	....	....	2,031,794	2,905,196	699,000	1956
1955	41,971	2,225	854	625,243	591,234	2,450	6,133,899	....	....	1,874,524	2,770,218	694,000	1955
1954	47,410	2,474	876	563,315	501,574	1,895	5,363,555	....	....	1,712,227	2,537,564	677,000	1954
1953	41,342	2,910	735	558,695	477,931	1,806	4,727,250	....	....	1,637,694	2,554,863	641,000	1953
1952	40,018	3,599	766	536,402	425,335	1,466	4,253,803	....	....	1,527,149	2,441,259	626,000	1952
1951	39,983	4,178	1,170	537,774	422,310	1,455	4,027,039	....	....	1,530,413	2,370,404	645,000	1951
1950	42,558	4,102	1,075	455,096	370,091	1,455	3,579,163	....	....	1,378,420	2,094,867	658,000	1950
1949	44,510	4,326	1,011	422,357	361,671	1,254	3,177,410	....	....	1,336,101	1,944,221	637,000	1949
1948	39,653	5,759	2,449	441,470	331,156	925	2,971,068	....	....	1,295,099	2,043,349	632,000	1948
1947	38,717	5,824	2,273	363,992	324,737	721	2,957,805	....	....	1,198,579	1,852,286	647,000	1947
1946	38,318	5,239	1,718	331,520	318,172	522	2,867,544	....	....	1,130,977	1,730,197	653,000	1946
1945	35,537	5,222	1,532	338,458	349,736	596	3,165,395	....	....	1,152,735	1,719,534	669,000	1945
1944	36,574	5,550	1,771	315,311	351,323	382	3,048,124	....	....	1,152,559	1,655,694	672,000	1944
1943	29,011	4,614	1,931	243,554	296,518	114	2,431,187	....	....	942,185	1,429,738	659,000	1943
1942	27,753	4,594	1,776	201,670	265,743	53	2,041,537	....	....	839,712	1,334,103	629,000	1942
1941	33,105	4,517	1,091	148,127	283,021	73	1,862,996	....	....	827,320	1,409,192	584,000	1941
1940	32,055	4,428	979	129,007	252,914	113	1,679,072	....	....	747,592	1,294,162	579,000	1940
1939	31,756	4,009	742	97,683	246,188	123	1,565,234	....	....	697,442	1,237,840	555,000	1939
1938	28,855	3,467	722	109,741	233,791	75	1,400,479	....	....	669,956	1,165,015	567,000	1938
1937	27,549	4,750	1,209	113,005	224,675	84	1,310,539	....	....	653,866	1,183,440	552,000	1937
1936	30,654	4,937	1,310	93,133	210,659	123	1,191,023	....	....	639,149	1,068,570	597,000	1936
1935	31,617	5,178	1,221	80,175	183,393	117	1,071,841	....	....	591,231	966,243	615,000	1935
1934	33,263	4,702	1,189	79,965	164,748	194	1,022,984	....	....	571,471	895,636	635,000	1934
1933	33,292	4,995	1,059	66,333	172,085	263	900,468	....	....	558,460	861,254	648,000	1933
1932	34,501	3,924	958	67,467	161,634	233	845,816	....	....	557,490	819,997	692,000	1932
1931[5]	35,913	3,743	1,412	75,548	149,924	529	917,923	....	....	601,122	894,578	672,000	1931[5]
1930	46,936	....	1,949	98,542	121,321	580	826,640	....	....	623,443	927,447	672,000	1930
1929[6]	51,544	....	2,300	103,729	98,727	488	573,463	....	....	630,837	987,738	639,000	1929[6]
1928	46,429	....	3,362	114,950	77,313	470	....	....	....	609,216	913,295	667,000	1928
1927	42,452	....	3,031	123,395	53,465	450	....	....	....	597,497	828,535	721,000	1927
1926	46,416	....	6,052	121,449	52,077	408	....	....	....	645,319	779,264	832,000	1926
1925	50,455	....	6,153	87,842	35,041	314	....	....	....	613,480	739,920	829,000	1925

[1] Includes small quantities of crude oil (less than one per cent) used directly as fuel.

[2] Includes catalyst coke.

[3] Includes purchased steam since 1935.

[4] Prior to 1957, liquefied petroleum gas and purchased steam are not reported separately.

[5] Prior to 1931, acid sludge is included with fuel oil.

[6] Prior to 1929, purchased electricity is not reported separately.

Authority: Bureau of Mines, *Mineral Industry Surveys*, "Petroleum Statements."

Source: American Petroleum Institute, Petroleum Facts & Figures, 1971 Edition.

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A very crude estimate of minimum requirements would be 2 acres per thousand barrels per day for the refinery itself. Actual total land for new grass roots refineries averages about 21.8 acres per thousand barrels per day.(L-9) This generally allows room for expansion. Existing refineries, which have been expanded, average about 12.5 acres per thousand barrels.

Fuel Oil Refinery

At the present time, import regulations encourage the importation of residual fuel oil while discouraging imports of other petroleum products. This import policy, combined with the conventional pricing of petroleum products, discourages production of fuel oil in domestic refineries. If a change in regulations were made, it is probable that a number of refineries might be constructed in the Eastern United States to maximize fuel oil. Such a refinery would be quite different from the conventional U.S. petroleum refinery. Although there are many different refinery configurations, for the purposes of this investigation it is expected that a typical topping refinery would include crude oil receiving and storage facilities, a crude desalting unit, atmospheric crude still, residual oil and distillate hydrodesulfurization units, a hydrogen plant, a sulfur plant, and product storage facilities. Sulfur dioxide emissions from the sulfur plant with and without a sulfur-plant tail gas desulfurization unit are considered in this section.

It is expected that the topping refinery would operate on a Mid-East crude. Refinery yields would be expected to be about 60 percent fuel oil and 30 percent naphtha. Unless otherwise indicated during the discussion, a typical Kuwait crude (2.5 percent S, 31.4° API)(L-10) is assumed as feed. The sulfur content of this crude would be about 7.6 pounds sulfur per barrel. It is assumed that the fuel oil from this refinery will have a sulfur content of 0.7 percent.

Air Emissions

The air emissions from the topping refinery will come from sources similar to those listed in Table L-2 for the conventional refinery but, because of differences in refinery configuration, there will obviously be differences in the emissions.

Sulfur Dioxide. Sulfur Plant. In a topping refinery, the two major sources of sulfur dioxide emissions will be the tail gas from the sulfur plant and sulfur dioxide emitted in combustion gases. Based on the assumptions stated in the description of the refinery, and ignoring the small amount of sulfur present in the naphtha, and assuming that the Claus sulfur plant will recover 95 percent of the sulfur from the desulfurization units, the emissions of sulfur dioxide in the rail gas from the sulfur plant would be 632 pounds sulfur dioxide per thousand barrels crude processed. Addition of a Beavon process or other process to remove sulfur from the sulfur plant tail gas would result in an overall recovery of about 99.8 percent and emissions would be reduced to 25 pounds per thousand barrels crude.

Combustion. Because the topping refinery is somewhat simpler than the conventional refinery, it is expected that somewhat less energy would be required for its operation. Although a detailed energy balance would be required in order to obtain an accurate figure, for the purposes of estimating the emissions, it has been assumed that the fuel oil consumption will be the equivalent of about 70 percent of the energy consumed in a conventional refinery. Assuming that the fuel emits 0.8 pound sulfur dioxide per million Btu (i.e., that the refinery is forced to burn fuel oil rather than natural gas) the emissions of sulfur dioxide from combustion in the refinery would be about 380 pounds per thousand barrels crude run to stills.

Nitrogen Oxides. Essentially all nitrogen oxides from the topping refinery would result from combustion operations. It is anticipated that fuel oil and refinery gas will be the only source of refinery energy for such a refinery. Assuming that the topping refinery uses about 70 percent of the energy per barrel consumed in a conventional refinery, and using the standard emission factor of 2.9 pounds nitrogen oxide per barrel oil burned,(L-2) the emissions of nitrogen oxide would be about 170 pounds per thousand barrels of crude processed. It is assumed that nitrogen oxide emissions will be somewhat reduced by improved burner design. To allow for this reduction, emissions due to burning refinery gas were ignored.

Particulates. In the topping refinery the combustion of refinery fuel will account for essentially all particulate emissions. Based on the same assumptions discussed above, and using the standard emission factor of 0.84 pound particulates per barrel oil burned,(L-2) the particulate emissions would be 49 pounds per thousand barrels crude oil processed.

Carbon Monoxide. The emissions of carbon monoxide from the topping refinery will be negligible.

Hydrocarbons. Hydrocarbon emissions in the topping refinery will originate from storage tanks, loading and transfer facilities, and accidental spills and leaks. Because a typical topping refinery will have a smaller quantity of light products than the conventional refinery which is designed to maximize gasoline production, the hydrocarbon emissions from the topping refinery will be less. Thus, the emission level of about 140 pounds hydrocarbon per thousand barrels crude from a conventional refinery with good emission controls will set an upper limit. Assuming the emissions are about 60 percent of those from the conventional, gasoline-maximizing refinery, the hydrocarbon emissions would be about 84 pounds per thousand barrels crude run to stills.

Water Pollution

The major sources of water pollution from a topping refinery will be the same as those from a conventional refinery, although the quantities of phenols will generally be lower. The quantity of water pollutants from a modern topping refinery were derived using our best judgment from the data collected in 1967 (see Table L-4). These estimates, which are highly subjective, are summarized in Table L-7.

TABLE L-7. ESTIMATED AQUEOUS EFFLUENTS FROM NEW TOPPING REFINERIES

	Pounds per Day per Thousand Barrels per Day
BOD	30
COD	110
Oil	8
Phenols	0.8
Suspended solids	20
Dissolved solids	500
Alkalinity	nil
Sulfide	0.5
Phosphorus	1
Nitrogen	4

Energy Consumption

A detailed energy and material balance would be required to estimate the fuel consumed in a topping refinery. Although the energy requirements may be somewhat lower than that for a conventional refinery because there are fewer stills, pumps, etc., there are a number of units like the crude still and hydrogen plant that will consume significant quantities of energy. Therefore, as a first approximation it is assumed that the topping refinery, like the conventional refinery, will consume about 700,000 Btu per thousand barrels crude run to stills. Further, it is assumed that about 70 percent will be supplied as fuel oil, 30 percent as low-sulfur refinery gas, and light distillates.

Allocation of Pollutants to Products

A petroleum refinery makes numerous products, and it is rarely possible to associate a specific pollutant with any one product. For the purposes of calculating the emissions associated with the modules in this study, the emissions were allocated on the basis of the heat content of crude oil input. The world average heat value of 5,850,000 Btu per barrel crude oil was used.(L-11) This is somewhat higher than the U.S.

average of 5.6 million Btu per barrel crude. It is anticipated that new refineries will rely almost totally on foreign crude. Therefore, the world average was thought to be the better value. A further assumption used in allocating pollutants was that all the energy consumed in refinery operation will be derived from crude oil or petroleum products. A sample calculation of nitrogen oxide emissions based on these assumptions is carried out as follows:

$$\frac{0.130 \text{ lb NO}_x\text{/bbl crude}}{5.85\ 10^6 \text{ Btu/bbl crude} \times \left(1-\frac{704}{5850}\ \frac{\text{Btu consumed}}{\text{Btu input}}\right)} = 0.0254 \text{ lb NO}_x/10^6 \text{ Btu}$$

Several alternative methods of allocation could be used. For example, pollutants could be allocated on the basis of product yields and product heat content.

Typical product distribution based on volumes are(L-6)

	Conventional Refinery	Fuel Oil Refinery
Gasoline	0.524	
Naphtha not elsewhere included	0.007	0.33
Jet fuel	0.075	
Kerosene	0.024	
Distillate fuel oil	0.224	
Residual fuel oil	0.064	0.67
Petrochemical feed stocks	0.025	
Other Products	0.057	
	1.000	1.00

In 1970, the volume gain on processing refinery inputs (including rerun oils and natural gas liquids) was 3 percent. This is a typical value for conventional refineries.

Typical heat values are(a)

Crude oil, U.S. average(b)	5,600,000 Btu/barrel
Gasoline	5,248,000
Kerosene	5,670,000
Distillate fuel oil	5,825,000
Residual fuel oil, high sulfur	6,287,000
Residual fuel oil, low sulfur	6,000,000
Jet fuel, naphtha-type	5,355,000
Jet fuel, kerosene-type	5,670,000

(a) All but low sulfur fuel oil based on U.S. Bureau of Mines, "Crude Petroleum", 1970 and 1969.

(b) 5,600,000 Btu per barrel is U.S. average. World average is 5,850,000 Btu/bbl. (International Petroleum Encyclopedia, 1972 edition).

Another approach would be to attempt to allocate the pollutant to the source within the refinery, and thence to the specific product. Most of the sulfur is concentrated in the heavy fractions of crude oil and could be logically allocated to the residual fuel oil and other heavy products. Similarly, the carbon monoxide from regeneration of cracking catalysts could be logically assigned to gasoline manufacture.

For the purposes of policy planning, little advantage is seen in attempting to apply increasingly sophisticated allocation methods. The final results should not be greatly affected by the allocation method, and the method used is believed to be suitable.

Alternatives have been briefly discussed to enable the reader to make his own judgments and modifications to suit his specific purpose.

By-Products

The major nonfuel by-products from a petroleum refinery are sulfur and petrochemical feedstocks. Petrochemical feedstocks, which can also be used as fuel, have not been considered in this study.

In 1966, 30 percent of the sulfur contained in crude oil went into the products.(L-1) This would have been the equivalent of about 0.23 percent sulfur in the crude ending in the products. Since 1966, the sulfur content of No. 2 heating oil has decreased about 12 percent and of No. 6 fuel oil (residual) by about 3 percent.(L-6) Most of the sulfur in products is not in these heavier fractions. To allow for further reduction in the sulfur content of petroleum products, it has been assumed that the equivalent of 0.2 percent sulfur in the crude oil will be in the products.

For the purposes of estimating sulfur by-product, it is assumed that the remaining sulfur present in the crude oil is converted to elemental sulfur, and that this sulfur is allocated on the basis of heating value of the crude oil less the energy consumed as refinery fuel. A density of 7.29 pounds per gallon (API 30) was assumed. A sample calculation of sulfur by-product for crude with 2.5 percent S is carried out as follows:

$$\frac{(2.5-0.2)}{100}\ \frac{\text{lbs}}{\text{lb crude}} \times \frac{7.29(42)}{6.3}\ \frac{\text{lb crude}}{10^6\ \text{Btu}} \times \frac{1}{0.88}\ \frac{\text{Btu crude}}{\text{Btu products}}$$

$$= 1.27\ \text{lb S}/10^6\ \text{Btu}.$$

Based on these assumptions, the approximate production of by-product sulfur from the processing of various crudes is summarized below.

Crude	Sulfur in Crude, %	Sulfur By-Product, lb/million Btu
Nigeria (Delta)	0.18	0
1966 Domestic Mix	0.76	0.33
Alaska (Prudhoe Bay)	0.86	0.39
Venezuela (Tia Juana)	1.5	0.77
Saudi Arabian Mix	1.63	0.85
Kuwait	2.5	1.27

The accuracy of the data does not justify more sophisticated estimates. The next level of sophistication would take actual product sulfur contents and the sulfur dioxide emissions into account. The improvements obtained by such a calculation would be small compared to the uncertainties in the source and composition of crude oil.

Cost of Pollution Control

The cost of pollution control by refineries may be broken down into the costs due to the use of low-sulfur fuel for refinery operations and the costs due to installation of equipment to control emissions other than those from fuel combustion.

Nonfuel Costs

The measures which must be taken to reduce pollution from refineries under current or anticipated regulations include

1. Removal of hydrogen sulfide from all refinery fuel gases, conversion of this hydrogen sulfide to elemental sulfur in sulfur plants equipped with tail gas scrubbing

2. Installation of floating roof tanks for all gasoline and volatile crude storage tanks with capacity greater than 40,000 gallons

3. Installation of electrostatic precipitators to remove catalysts fines from the vent gases from cracking catalyst regeneration units. It is anticipated that controls would be required only on units with capacities over 10,000 barrels per stream day. (This excludes 27 crackers in 25 refineries representing 10 percent of the total cracking capacity.)

4. Incineration of the gases from regeneration of cracking catalysts in a carbon monoxide boiler. (The same exclusion of small units as in Number 3 is anticipated.)

5. Reduction of biological oxygen demand, and removal of oil and suspended solids from waste water in an effluent treatment plant.

In a new refinery, the cost of installing the necessary pollution control equipment described above is estimated to be $46 per daily barrel of capacity, while in existing refineries the cost is estimated at $56 per daily barrel.(L-12) Assuming that capital related charges amount to 35 percent of capital investment annually, this would amount to $0.045 per barrel crude processed in new refineries. These capital related charges could be broken down to include 6.25 percent for depreciation (16 year, straight-line); 2.75 percent for insurance, taxes, etc.; 3 percent for maintenance costs; and 23 percent before tax return-on-investment. The costs of operating pollution control equipment is estimated at $0.004 per barrel crude.(L-12) Thus, the expected increase in the cost of petroleum products from new refineries which is attributable to the installation of pollution control equipment, would be about $0.05 per barrel crude run to stills.

Fuel Costs

It is very likely that a new refinery will be unable to purchase natural gas for use as a refinery fuel, and will therefore burn residual fuel oil. Most of the process heaters in refineries have heat inputs of less than 250 million Btu per hour and are exempt from the Federal sulfur emission regulations. Depending upon the refinery location, state regulations would probably require the use of a low-sulfur fuel.

In a typical refining operation, about 700,000 Btu are required per barrel crude oil processed. Assuming 30 percent of this heat requirement can be supplied by burning refinery gases, the remaining 70 percent would be supplied in the form of fuel oil. It is also possible that a refiner might burn crude oil, but the crude oil is more valuable than the heavy fuel oil. Unless there is some extreme economic distortion caused by Government action, crude oil will be refined rather than consumed as refinery fuel. If one assumes that the fuel oil must be low sulfur (0.7 percent) and is valued at $3.50 per barrel, and that current refiners consume natural gas valued at $0.22 per million Btu, the increased cost due to the use of low-sulfur fuel oil would be about $0.17 per barrel crude run to stills. In practice, the cost increase will be a function of specific refinery characteristics, but it will probably be in the $0.15 to $0.20 per barrel range.

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APPENDIX M

GASIFICATION OF CRUDE OIL AND NAPHTHA

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APPENDIX M

GASIFICATION OF CRUDE OIL AND NAPHTHA

Crude Oil Gasification

Summary

As of late 1972 there are no gasification plants anywhere of the sizes proposed for the United States, for either naphtha or crude oil. Technology for the gasification of light petroleum feed stocks such as naphtha has been developed and there are over 70 such plants in Europe and Japan.(M-1) However, these plants produce a gas in the 500 to 560 Btu/scf range, lower than that required for SNG (1,000 Btu/scf). The relatively limited supplies of naphtha will necessitate addition of crude oil as a feed stock rather quickly and, within a few years, the majority of plants producing SNG will undoubtedly be based on crude oil with the products being SNG and low-sulfur fuel oil. Gasification processes will be based on the Catalytic Rich Gas (CRG) process, the Methane Rich Gas (MRG) process, the Fluid-Bed Hydrogenation (FBH) process, or variations of these.

The projected emissions of air pollutants from crude oil SNG plants during the 1975 to 1990 base period are estimated to be approximately as follows:

	lb/M bbl Input	$lb/10^6$ Btu (Output)	lb/MWhr
SO_2	250-500	0.05-0.10	0.50-1.0
Particulates	10	0.002	0.02
CO	Negligible	Negligible	Negligible
HC	20	0.004	0.04
NO_x	400	0.08	0.8

Salt content of crude oil may be in the range of 100 lb/M bbl, and one of the principal liquid wastes from a crude oil SNG plant will be the brine resulting from desalting the crude oil. With proper precautions there will be almost no other liquid wastes issuing from a well-designed SNG plant.

Solid wastes attributable to the production of SNG from crude oil will include those from the treatment of the water required by the plant, and from treatment of the waste streams. There will be, in addition, discharges of spent catalysts not worth reclaiming. As an approximation, a figure of 0.25 T/M bbl (based on one projected plant design) is taken.

Because of the wide variety of feed stocks and purification techniques available, it is difficult to present meaningful cost information. Based on some unpublished information, cost of conversion of a high-sulfur crude to SNG is in the range of \$0.50-0.60/10^6 Btu (for a 100,000 bbl/day plant). This does not include the cost of the crude oil. To obtain the SNG selling price, calculate the crude price in \$/10^6 Btu and multiply by a factor of 1.3 (i.e., 1/0.77) due to the thermal efficiency of the plant, and add it to the crude-to-SNG conversion cost given above.

Technology

As of late 1972 there are no gasification plants anywhere of the sizes proposed for the United States, for either naphtha or crude oil. There are also no plants producing a substitute natural gas (SNG) with the heat content of 1,000 Btu/scf required in the United States for pipeline quality gas. Technology for the gasification of light petroleum feed stocks such as naphtha has been developed and there are over 70 such plants in Europe and Japan.(M-1) However, these plants produce a lower-Btu gas, in the 500 to 650 Btu/scf range.

The technology required for the gasification of crude oil is available, in that the several operations involved have been individually proved, but to date they have not been demonstrated as a unified whole. For this reason, and because of the present costs and availability of naphtha, most (20 or so) of the gasification plants projected for the immediate future will gasify naphtha.(M-2) However, the relatively limited supplies of naphtha will necessitate addition of crude oil as a feed stock rather quickly and within a few years the majority of plants producing SNG will undoubtedly be based on crude oil. By 1975 it is estimated that there will be at least a half-dozen crude oil SNG plants constructed, with a capacity of 2,500 to 4,000 10^6 cu ft/day. By the fall of 1972 seven crude oil to SNG plants had been proposed, all of 100,000 bbl/day or more capacity. All will make SNG and all but two will make low-sulfur fuel oil as well.(M-3) Gasification processes used will be the Catalytic Rich Gas (CRG) process, the Methane Rich Gas (MRG), or the Fluid-Bed Hydrogenation (FBH) process, or variations of these. Another possibility is to utilize existing conventional refinery technology to crack middle distillates and heavier to naphtha by hydrocracking followed by gasification of the naphtha. This will probably be in conjunction with production of low-sulfur residual fuel oil as a co-product.(M-4) The heavy residue may be coked, with subsequent gasification of the coke to produce a low-Btu gas (100-150 Btu/scf) for plant consumption.

A typical flowsheet for this scheme is illustrated by one proposed by M. W. Kellog Company for the lower-cost, fairly high-sulfur crude that is usually most readily available to the energy refinery.(M-3) The process is shown schematically in Figure M-1. Basic elements of the process are as follows:

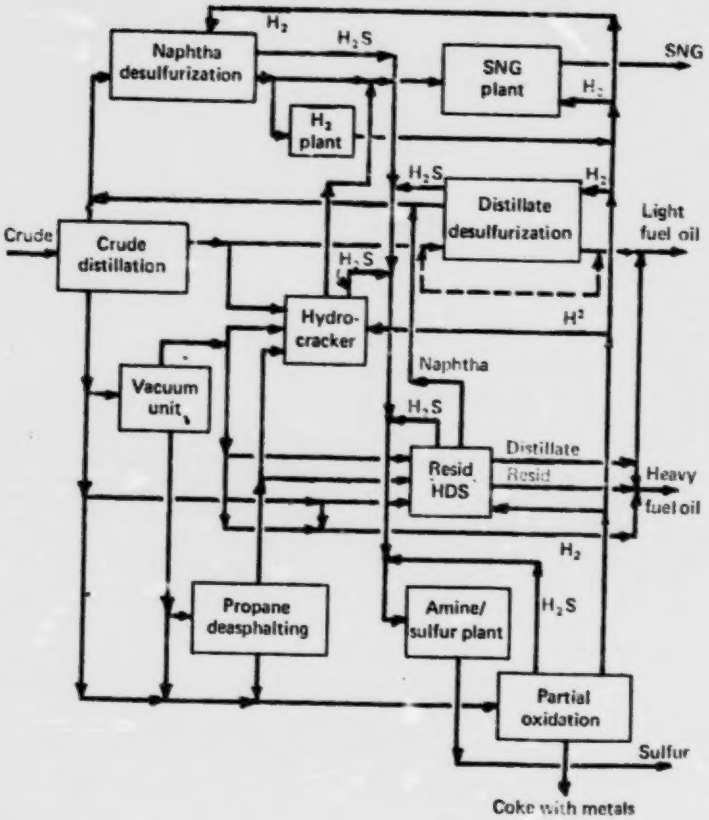
H_2
H_2S
Naphtha desulfurization
SNG plant
SNG
H_2
H_2 plant
H_2S
H_2
Distillate desulfurization
Light fuel oil
Crude
Crude distillation
H_2S
Hydrocracker
H^2
Naphtha
Vacuum unit
H_2S
Distillate
Resid
Resid HDS
Heavy fuel oil
H_2
Propane deasphalting
Amine/sulfur plant
H_2S
Partial oxidation
Sulfur
Coke with metals

FIGURE M-1. SCHEMATIC DRAWING OF ENERGY REFINERY FOR PROCESSING HIGH-SULFUR CRUDE OIL

"Virgin naphtha from crude distillation goes directly to the SNG plants, after desulfurization. Atmospheric and vacuum gas oils are either hydrocracked to make more naphtha for the SNG unit or are hydrodesulfurized for low-sulfur fuel oil. Asphalt or crude stillbottoms are partially oxidized to make the hydrogen needed for the hydrocracker and the various desulfurization units. H_2S is converted to elemental sulfur.

With lighter crude oil such as Iranian light, the flowsheet could be simplified. The vacuum distillation unit might not be required, and the deasphalting and partial oxidation wouldn't be needed. Furthermore, a light crude might be desulfurized whole, doing away with the need for downstream desulfurizing of various products. Thus, this energy refinery would be little more than a topping plant, typical of the overseas refineries built to make naphtha and fuel oil."

All of these processes will require methanation of the initial gas product in order to increase its heating value to the 1,000 Btu/scf required for pipeline gas. If the gas were produced in a satellite plant connected to a central power station, a lower-Btu gas would suffice, and the methanation step could be avoided. This may be a future development over the next decade.

Since the basic SNG process technology has not yet reached the stage of normal commercial application, neither has the pollution control technology which will be associated with these plants. Nevertheless, the control problems are sufficiently analogous to those of refineries that they can be satisfactorily defined.

Environmental Factors

Air. The principal pollution problem will undoubtedly be sulfur dioxide. Characteristically, crude-oil SNG plants will draw their feed stocks from lower-grade, nonpremium crudes, and sulfur contents in the 2 to 4 percent range will be typical. Thus, for a nominal 100,000 bbl/day plant, from 325 to 650 T/D of sulfur must be disposed of. Most of the sulfur will be released during processing as H_2S, which is amenable to removal and recovery by successfully demonstrated processes. Usually this will be accomplished by a Claus plant, backed up by a tail gas treatment plant using one of several available processes. Total recoveries in the 99.5+ percent range can be achieved on the main gas stream with "reasonably available technology". Depending on the particular processing scheme employed, an overall plant sulfur removal of about 98 percent can be anticipated in the 1975-80 period. For "typical" crudes available for SNG, this will place SO_2 emissions in the range of approximately 250 to 500 pounds SO_2/M bbl processed.

The sulfur found in either the residuum or the coke will not be as easily recovered. Several hundred tons of coke per day is produced, which may be high in sulfur unless the feed is hydrodesulfurized before coking. If the coke is burned for fuel directly, flue gas scrubbing or a comparable control measure may be necessary to meet existing regulations. Alternatively, the coke can be gasified by a partial oxidation scheme, and the low Btu gas desulfurized before its utilization as refinery fuel. Another alternative incorporates a hydrodesulfurizer and fluid catalytic cracker ahead of the coker, which will reduce the sulfur content of the coke.

SNG plants will supply their own fuel. Normal fuel for the various process heaters and furnaces will be hydrodesulfurized oil or refinery gas drawn from the process (otherwise the sulfur content would be far too great). These will be high-grade fuels, low in sulfur, and SO_2 and particulate emissions will be minimal.

Particulate losses may be expected to occur primarily where any coke produced is burned or in the catalyst regenerator, if a cat-cracker is included in the process flowsheet.

If a cat-cracker is used, approximately one-third of the fresh feed may be cracked. With previous technology, characteristic particulate emission rates found by EPA were about 61 lb/M bbl of fresh feed,(M-5) equivalent to approximately 20 lb/M bbl of refinery throughput. With present particulate removal technology, this is substantially reduced, to the extent that total particulate emissions in the range of 10 lb/M bbl of crude oil input are anticipated for SNG plants.

CO emissions will have significant potential only in the case where a cat-cracker is employed. However, since use of CO boiler for combustion of regenerator gases will undoubtedly be required by soon-to-be-enacted regulations, CO emissions will be negligible, in the few ppm range.

Hydrocarbon emissions from an SNG plant will be essentially only those from tankage; any other hydrocarbon emissions should be minimal, since the processing is conducted in a closed system, and there are not the multiplicity of products to work up and clean up, as in the usual refinery.

The product SNG is not stored so any hydrocarbon losses are restricted to feed stock and intermediates storage. In order to insure continuity of operations, total feed stock and intermediates storage will probably be in the range of 50 days throughput. However, since the major stored materials are the relatively nonvolatile crude oil, residuum, and gas oils, losses are negligible. Based on EPA emission factors, daily losses of no more than 20 lb/M bbl throughput are estimated.

Nitrogen oxides will be released in all combustion operations; by suitable design of the combustion equipment these can be kept below the allowable level of 0.3 $lb/10^6$ Btu permitted by present EPA regulations for new stationary sources burning liquid fuel.

Energy efficiency of a crude oil SNG plant will be in the 75 to 80 percent range, i.e., 75 to 80 percent of the input Btu's are available in the product gas. The other 20 to 25 percent is consumed in the operation of the process. Taking an average energy efficiency of 77 percent and assuming all of the 23 percent consumed is as liquid fuel, total allowable nitrogen oxide emissions are approximately 400 lb/M bbl.

Water. Salt content of crude oil may be in the range of 100 lb/M bbl, and one of the principal liquid wastes from a crude oil SNG plant will be the brine resulting from desalting the crude oil.

There will, of course, also always be concentrated blowdown streams from boilers and cooling towers to dispose of. These will most likely be combined with the desalter brine for disposal. It will not be possible to dispose of these waste streams to water courses. Possible disposal procedures are to utilize them as water ballast for the tanker supplying the crude or to dispose of them to the ocean (for seacoast SNG plants). In numerous locations, inland plants will be able to dispose of them to deep injection wells. By a suitable combination of chemical and physical processing, including biological treatment, an essentially closed water cycle can be established, except for the brine and the blowdowns. Thus, there will be almost no liquid wastes issuing from a well-designed SNG plant.

Solid Waste. Solid wastes attributable to the production of SNG from crude oil will include those from the treatment of the water required by the plant, and from treatment of the waste streams. There will be, in addition, discharges of spent catalysts not worth reclaiming. As an approximation, a figure of 0.25 T/M bbl (based on one projected plant design) is taken.

Land Use. An SNG plant gasifying 100,000 bbl/day of crude oil will require a site of 500 acres or greater in size for the plant, the associated tank farm, and a solid waste disposal area. To minimize possibilities of environmental impact upon its neighbors, site size will frequently be increased over this; 1000 acres is taken as a nominal figure.

Other Environmental Factors. Of the energy input to a crude oil SNG plant, about 77 percent is recovered as product; the other approximately 23 percent is consumed in the processing operations and is rejected to the environment in the form of heat. Taking crude oil at 6 x 10^6 Btu/bbl, thermal energy liberated is about 1,400 x 10^6 Btu/M bbl. Except for the heat rejected in flue gases (possibly 20 to 25 percent), the manner of rejection of the remainder is primarily a function of plant design. Whether the heat is rejected to water or to the air will depend upon the particular circumstances of a given plant, and may range almost anywhere between the two extremes. In the tabular summation of data given in Appendix A, a nominal value midway between the extremes was selected.

Pollution Controls

Methods. As noted earlier, by far the greatest problem in producing SNG from crude oil is the removal of sulfur. The basic method is based on the splitting of the sulfur from the oil by treatment with hydrogen (hydrodesulfurization) and treatment of the evolved H_2S by the Claus process. In the Claus process H_2S is combusted under precisely controlled conditions so that one-third of it is converted to SO_2. The cooled combustion products are catalytically reacted to form elemental sulfur:

$$2H_2S + SO_2 \rightleftharpoons 3S + 2H_2O$$

after which the sulfur is condensed and separated. However, recovery is not complete even with three converters, and as much as 5 percent of the entering sulfur is contained in the exit (tail) gas. Recently developed technology (e.g., The Beavon, Cleanair, and IFP processes) achieves recovery of almost all of the remainder. Gradual improvements will be made in tail gas cleanup. However, there is not much room for further improvement, since present regulations already require 99.5 percent elimination, and exit gas concentrations are already down to a few hundred parts per million.

The principal improvements will come in the cleanup of SO_2-containing flue gases. The problems of flue gas cleanup are described elsewhere in this report and are not repeated here. There are unavoidably some combustion operations in SNG plants with sulfur-containing fuels, and the remaining reductions in sulfur emissions will occur in this area.

By 1990, 99.0 to 99.5 percent removal of the sulfur input to a crude oil SNG plant can be envisioned. This will reduce unit emissions from the 250 to 500 lb/M bbl in the 1975 to 1980 base period to the 65 to 250 pound range, assuming sulfur levels in crude to not increase significantly.

Particulate emissions in a crude oil SNG plant are comparable to those occurring from steam generators fired with solid fuels, and the same types of control equipment are used. No breakthroughs in particulate emission control technology for SNG production are foreseen over the 1975 to 1990 period. Improvements are more likely to result from the application of already-known more complex and costly techniques to situations not heretofore regarded as warranting their use. Electric precipitators and baghouses instead of cyclone separators are examples of this substitution; their use will undoubtedly increase as particulate emission limitations become more stringent.

Hydrocarbon emissions in a crude oil SNG plant are associated primarily with storage of petroleum fractions. Control is achieved by the use of floating roof tanks, for moderately volatile materials such as crude oil, and by pressure vessels for the volatile materials like propane and butane. Rates of hydrocarbon emissions are minimal from a modern plant of this type, and little changes in technology are anticipated.

CO emissions may be large from an uncontrolled fluid cat-cracker regenerator, but are reduced to insignificant levels by the addition of a CO boiler. Since it is unlikely that any new FCC units will be built without a CO boiler, CO emissions are not expected to be a problem in any SNG plant.

Effectiveness and Cost. Data are not available on the cost of the individual pollution control measures applied to the manufacture of SNG from crude oil. However, the conversion of high-sulfur crude oils to SNG is in itself a pollution control measure, which can be compared with other alternative pollution control measures, e.g., hydrodesulfurization of crude oil, or flue gas scrubbing.

The extent to which SNG from crude oil is utilized as a future energy source in the United States will depend in large measure upon a number of factors, including the relative availability and cost of crude oil feed stock versus alternative sources, the relative cost of conversion to SNG, and the costs of pollution control. Each of these factors has its own set of variables, so that generalizations are difficult. However, one generalization that can be made is that the more energy expended in converting a fuel to another form, the higher will be the cost per net Btu. Accordingly, the manufacture of SNG from crude oil will inevitably be more costly on a unit basis than merely desulfurizing crude to make fuel oil.

Thus, for major energy users such as central power stations, desulfurized fuel oil will be basically a cheaper fuel than SNG. Depending on size, location, and age of plant, it may be more economical for an existing generating plant burning gas to convert to burning fuel oil than to continue to burn gas, when that gas has the \$1+/M cu ft cost of SNG. It may also be more economical for such a plant to burn desulfurized fuel oil than to install a flue gas scrubbing system.

The principal alternative processes for manufacture of a low-sulfur fuel not requiring flue gas scrubbing are desulfurization of crude oil, manufacture of SNG from crude oil, and manufacture of SNG from lighter petroleum fractions such as naphtha. Because of the wide variety of feed stocks and purification techniques available, it is difficult to compare meaningful cost information. However, the costs are believed to compare as follows. Cost of conversion of naphtha to SNG is in the range of \$0.27 to 0.30/10^6 Btu for a complete plant of 250 x 10^6 cu ft/day (50,000 bbl naphtha/day) capacity.(M-2) Based on some unpublished information, cost of conversion of a high-sulfur crude to SNG via a naphtha intermediate is in the range of \$0.50 to 0.60/10^6 Btu. This is confirmed in essence by the data presented by Prescott.(M-3)

The difference between naphtha gasification and crude oil gasification via naphtha ought to be approximately equivalent to the production of desulfurized fuel oil, or a little more, since less processing is needed to produce fuel oil than naphtha. From the data above, this would place the cost in the range of \$0.25 to 0.35/10^6 Btu. This is confirmed by Chapel and Rogers(M-6) in which desulfurization of whole Kuwait (high-sulfur) crude to 0.6 percent sulfur was estimated to cost \$1.35 to 1.50/bbl fuel oil, or about \$0.22 to 0.25/10^6 Btu.

The costs of pollution control will also influence the choice of energy source. Costs for flue gas scrubbing have been projected in the range of \$0.10 to 0.70/10^6 Btu, decreasing with increasing size of plant and increasing with increasing percentage of sulfur in the fuel. The spread is obviously so broad that each individual case would be decided on its own merits. However, it is apparent that for central power stations, for example, at least in some instances burning of high-sulfur residual fuel oil and scrubbing the flue gas would be the optimum economic solution. In other cases, the alternate options of the use of desulfurized fuel oil or SNG might lead to the lowest overall cost. The optimum choice will be clearly indicated in the usual industrial applications and the use of SNG will normally be the preferred choice for space heating, in spite of its higher cost because it can be easily utilized in existing gas-fired furnaces.

Naphtha Gasification

A process has been developed by the British Gas Council and M. W. Kellogg to produce a synthetic natural gas having a gross heating value of 1000 Btu/scf. Recently, the M. W. Kellogg Company prepared a report on the process and an inventory of both gaseous and liquid emissions from the process.(M-7) The description of the process and emission values are summarized here from that report.

Process Description

The feed stock to the process is a naphtha stream containing 500 ppm of sulfur. The gas produced is about 98 percent CH_4, with some H_2, CO, and CO_2.

The first part of the process is a naphtha desulfurization. The sulfur removal is accomplished by mixing naphtha vapor with a hydrogen-rich stream, and passing this mixture over a catalyst to produce H_2S. The H_2S is converted to sulfur via the Claus process.

Naphtha reforming is done by passing naphtha vapor and steam over a catalyst to produce CH_4, H_2, CO_2, and CO. This stream is then sent to a methanator in which the CO and some of the CO_2 react with H_2 gas to form CH_4 and H_2O. Cooling the gas at this point removes the water, leaving a stream containing mainly CH_4 and CO_2.

The CO_2 in the gas is then absorbed in a hot K_2CO_3 system to reduce the CO_2 content to less than 1 percent. Finally, the synthetic natural gas is dried with glycol.

Major Effluents From the Naphtha Gasification Process

The gaseous emissions and the liquid wastes are shown in Tables M-1 and M-2, respectively. The major gaseous pollutants are NO_x from the furnaces and methane from the CO_2 stripping.

TABLE M-1. GASEOUS EMISSIONS FROM NAPHTHA GASIFICATION PLANT (250×10^6 scfd)

Operation	Pollutant	Quantity, TPD	Concentration, ppm
Furnace	SO_2	0.56	55
	HC[(a)]	0.24	23
	NO_x[(a)]	4.7	460
Claus plant	SO_2	0.02	
CO_2 stripper	CH_4	10	83
Condensate stripper	CH_4	0.2	1600
TOTALS	SO_2 = 0.58 TPD CH_4 and HC = 10.44 TPD NO_x = 4.7 TPD		

(a) Based on emission factors from Reference M-5.

TABLE M-2. LIQUID EFFLUENTS FROM NAPHTHA GASIFICATION PLANT (250×10^6 scfd)

Operation	Dissolved Solids Quantity, TPD	Concentration, ppm
Boiler blowdown	0.48	1500
Cooling tower blowdown	0.67	1770
Backwash water from boiler water treatment	17.3	34,000
TOTAL	18.5 TPD	

The wastewater from the boiler, cooling tower, and water treatment plant contain ionic constituents such as $NaSO_4$, $CaSO_4$, $MgSO_4$, and $NaHCO_3$. At present, it is planned to neutralize the backwash water to a pH of about 8.5 before discharging to a stream or river and to discharge the other two directly as their pH is high.

Controls. The control of SO_2, NO_x, and hydrocarbons is discussed elsewhere in this report. The major problem in control arises in consideration of the liquid streams containing soluble ionic constituents. These ionic constituents have essentially no economic worth. One method of handling these wastes would be to use a process proposed by Maneval(M-8) namely, flash evaporation, followed by casting the molten salt into cubes, encasement in plastic, and burying the cubes. Maneval estimated the cost of a plant to process 5 x 10^6 gallons/day would be $14 million with direct operation costs of $0.40/1000 gallons. The plant for naphtha desulfurization discharges about 0.3 x 10^6 gallons/day. Using a cost index of 0.6 (a fairly common value in the chemical industry), and capital charges of about 25 percent, a plant to treat the liquid waste effluent would cost about $2.7 million, capital, and operating costs of $0.008 per 1000 ft^3 of gas. This represents a small increase in plant cost of about 1 percent, and an increase in gas cost of about 0.5 percent for control of the liquid waste effluent streams.

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APPENDIX N

PHYSICAL DESULFURIZATION OF COAL

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APPENDIX N

PHYSICAL DESULFURIZATION OF COAL

Summary

The partial desulfurization of coal by physical means involves removal of impurities by methods that are employed in the separation of solids in the ore-dressing industry. Some coals are more amenable than others to these methods depending on the physical characteristics of the coal and the impurities it contains. However, the generalization may be made that, if all the coal mined in the United States were physically cleaned, about 30 percent of all the sulfur would be removed. No other proposed action has the prospect for such an immediate result. In addition, up to 50 percent of the ash is removed. This reduces transportation costs and reduces the load on the power plant ash-handling and particulate-collection facilities. There is a loss of about 10 percent of the coal during physical cleaning but the removal of greater amounts of impurities results in a net increase in the heat content of the coal. The cost of physical cleaning for eastern coal is about 66 mils per 10^6 Btu of product.

Typical emission factors arising from the process after application of controls may be as follows:

1. Air pollution resulting from the operation of thermal dryers expressed as pounds per 10^6 Btu

SO_x	0.002
NO_x	0.006
Particulates	0.010

2. Water pollution as a result of drainage from settling ponds and compacted and revegetated refuse piles in the amount of 0.001 pound of H_2SO_4 per 10^6 Btu.

3. Solid waste, in the form of tailings from the washing plant, ranging between 10 and 21 pounds per 10^6 Btu.

The typical costs of control have been estimated for the various sources as mils per 10^6 Btu

• Air	2.65
• Water	0.65
• Solid Waste	0.65

Introduction

Sulfur is present in coal in several forms. In the organic form it is chemically bonded to the carbon atoms and as such cannot be removed by physical means. In American coals it represents approximately 20 to 85 percent of the total sulfur present. The inorganic form is present mainly as the chemical species FeS_2 or ferrous disulfide, with relatively small amounts of the sulfates of calcium and iron. The total sulfur content of coal varies between less than 1.0 and more than 4 percent.(N-1) Also, there is a large variability in the percentage of removable sulfur not only in coals from different regions, but also in coals obtained from the same mine. This is illustrated by Figure N-1 in which total, removable and organic sulfur were determined for samples of a Pittsburgh seam coal.(N-2)

The amenability of the coal for sulfur removal by physical means is established by "float and sink" analyses or washability tests.(N-2) In these tests, the coal is crushed to various sizes and each size is introduced into vessels containing liquids in the specific gravity range of 1.2 to 2.0. The upper part of the range approaches the specific gravity of impurities such as shale or rock and the lower part approaches the specific gravity of pure coal. The specific gravity of pyrite is about 4.90.

In the above-mentioned vessels the float material is termed the yield while the sink material is called the refuse. Figure N-2 is a "float and sink curve" for a No. 6 Bed Illinois coal, showing the effect of the specific gravity of liquid effecting separation on yield and sulfur removal.(N-3) It is seen that, although sulfur removal is increased by using a low specific gravity liquid, the total yield of product coal in the float material is reduced. Steam coal cleaning plants operate with liquids of specific gravity about 1.6 and yields in the neighborhood of 85 percent.(N-3)

Technology

Coal washing has been carried out for the past several decades using many physical separation techniques singly or in combination. In 1965, the percentages of existing coal washing processes using one or more of the named unit processes are as follows:

Process	Percentages	Process	Percentages
Jigging	46	Classifier	2
Dense-Medium	28	Launder	1
Tabling	13	Flotation	2
Pneumatic	8	Total	100

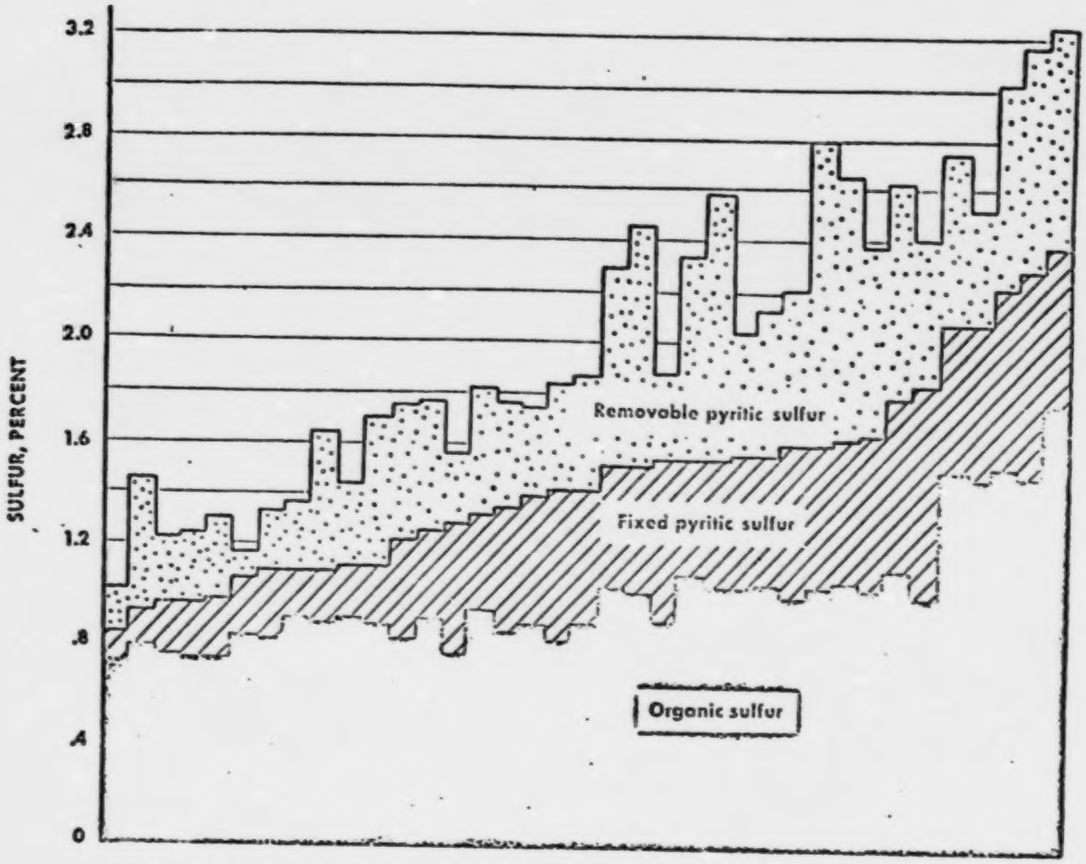

FIGURE N-1. VARIATIONS IN TOTAL SULFUR, SULFUR FORMS, AND REMOVABLE PYRITE IN FACE SAMPLES OF PITTSBURGH SEAM COAL FROM A SINGLE MINE IN GREENE COUNTY, PENNSYLVANIA. Ref. (N-2).

Note: Each bar represents one sample.

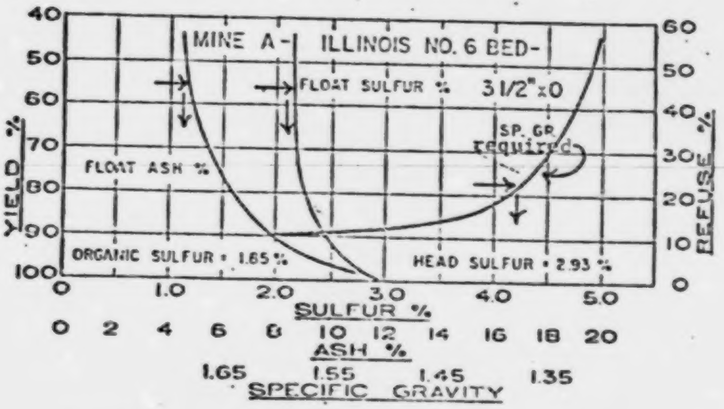

FIGURE N-2. FLOAT AND SINK CURVES FOR ILLINOIS NO. 6 BED COAL. Ref. (N-4).

A survey of the processes presented in Reference N-1 and inspection of the table mentioned above seems to indicate that the flowsheet given in Figure N-3 is fairly representative of current washing operations. In this process, run-of-mine coal is crushed to a top size of 3 inches and introduced into a Baum-type jig, where the bed of coal is subjected to up and down pulses of flowing dense medium of 1.6 specific gravity. This action results in a separation of the bed into three layers of differing specific gravity, the lowest layer containing the highest specific gravity or refuse material. The top layer is collected and further crushed to a top size of 3/8 inch and fed to the sieve bends of the dense-media cyclone plant. The 30 mesh x 0 material which passes through the screen is sent to the froth flotation plant whereas the 3/8 inch x 30 mesh material is sent through the dense-media cyclones. The dense medium is a slurry of magnetite in water of such concentration as to make the specific gravity 1.35. The float coal, of density less than 1.35, leaves the overflow orifice of the cyclone whereas the sink material exits the apex of the cyclone. Then it is washed, wet ground, and classified to 30 mesh x 0 and sent to the collecting sump of the froth flotation plant. In froth flotation of the fines, the coal particles surface is rendered nonwetable by treatment with collectors such as alcohols, pine oil, or kerosene to facilitate its adherance to rising air bubbles. Depressants such as lime or sodium cyanide are added to inhibit the rise of pyrite and clay particles. The resulting froth is skimmed, thickened and vacuum filtered, and sent to the thermal dryers along with the centrifugally dried 3/8 inch x 30 mesh float material from the dense-media cyclone plant overflow.

In all operations involving separation of pyrite and coal using dense medium of various compositions, the tailings as well as the product become contaminated with magnetite. Therefore, it is standard practice to have both rinsed before ultimate disposal of refuse or recovery of product. The magnetite in this rinse water is concentrated and most of it recovered by first thickening the rinse water and then passing the concentrate through a magnetic separator. Heavy medium losses may amount to 1 pound per ton processed at a cost of 3 cents/pound.

The average costs, in mils per 10^6 Btu, involved in cleaning eastern coals(N-1) may be broken down as follows:

• Depreciation	19.6
• Operation and Maintenance	22.9
• Tax	2.5
• Value of coal lost at $5.00/ton (ROM) and 90 percent yield	20.8
• Total mils/10^6 Btu	65.8

As mentioned earlier, only inorganic sulfur can be removed by means as previously described. It is believed that processes in operation today and those expected during the 1975 to 1990 period are inherently incapable of achieving total inorganic sulfur removal. The approach to this

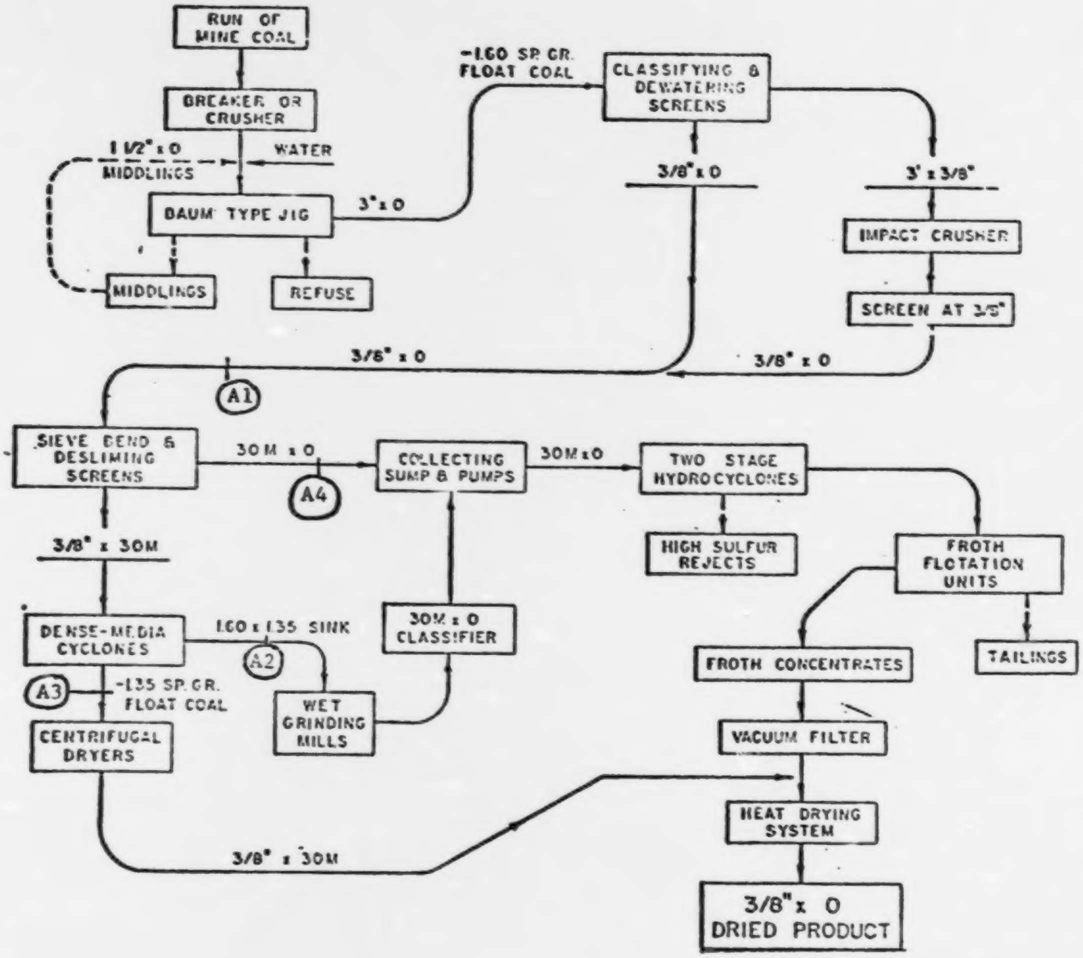
RUN OF MINE COAL
BREAKER OR CRUSHER
1 1/2" x 0 MIDDLINGS
WATER
BAUM TYPE JIG
3" x 0
MIDDLINGS
REFUSE
-1.60 SP. GR. FLOAT COAL
CLASSIFYING & DEWATERING SCREENS
3/8" x 0
3" x 3/8"
IMPACT CRUSHER
SCREEN AT 3/8"
3/8" x 0
3/8" x 0
A1
SIEVE BEND & DESLIMING SCREENS
30 M x 0
A4
COLLECTING SUMP & PUMPS
30M x 0
TWO STAGE HYDROCYCLONES
HIGH SULFUR REJECTS
FROTH FLOTATION UNITS
TAILINGS
3/8" x 30M
DENSE-MEDIA CYCLONES
1.60 x 1.35 SINK
A2
30M x 0 CLASSIFIER
A3
-1.35 SP. GR. FLOAT COAL
WET GRINDING MILLS
CENTRIFUGAL DRYERS
FROTH CONCENTRATES
VACUUM FILTER
HEAT DRYING SYSTEM
3/8" x 30M
3/8" x 0 DRIED PRODUCT

FIGURE N-3. A SCHEMATIC FLOWSHEET OF A COAL WASHING PLANT WITH 3/8 INCH x 0 PRODUCT, USING THE OPERATIONS OF JIGGING, DENSE-MEDIA SEPARATION, AND FROTH FLOTATION. Reference (3) limit would involve crushing the coal to relatively small sizes (200 mesh) and the extensive application of such fine separation processes as froth flotation. This is the subject of current research.(N-5) Current operations would give a typical yield of 80 to 90 percent and achieve inorganic sulfur removals of about 60 percent.

Environmental Factors

The coal-washing operations and processes that were previously described may have a significant effect on the environment. The consequence of washing large amounts of run-of-mine coal is the production of a proportionately large amount of refuse or waste material. Owing to increased mining by mechanical means and decreased availability of low sulfur fuels, refuse material from washing operations may be as high as 30 percent of the raw coal being processed.(N-1) Coal washing operations may affect both the air and water aspects of the environment. The assessment of the emissions from these operations will be made by adhering as closely as possible to data reported on the operational experience of the industry. Where no operational experience of emission factors was reported, estimates were made on the basis of coal with washability curves as given in Figure N-1. The plant was assumed to effect a separation at a typical specific gravity of 1.6 and have an output of 1000 tons per hour (tph).

Air

Here the most significant emission results from the operation of the thermal dryers.(N-6) The wet coal obtained from both fine and coarse separation is introduced to dryers operated by the combustion of pulverized coal. The hot gases resulting from this combustion are allowed to directly contact the wet product, thereby evaporating the water through the release of their sensible heat. In the absence of proper controls, particulates in the form of fine coal dust and ash from coal combustion together with the products of combustion, NO_x and SO_x, may be released. However, the recent enactment of more stringent air pollution regulations has resulted in the incorporation of gas cleaning devices as standard equipment in most recently modified or completed installations.(N-7) A description of these controls will be given in a later section. The emission factors with and without existing controls are presented in Table N-1.

Another potential source of air pollution may be the sulfur-rich coal-containing refuse obtained as sink material. If this waste is not properly disposed of, low temperature oxidation of the coal may take place and a gradual temperature buildup in the refuse pile may cause it to ignite spontaneously after the ignition temperature is reached. This may cause noxious emissions of SO_x, NO_x, and hydrocarbons. In 1966, there were 400 burning coal refuse sites of significance throughout the 15 of 26 coal-burning states in the United States.(N-1) However, there are no current data available on the extent of emissions resulting from the burning of refuse piles.

TABLE N-1. EMISSION FACTORS FROM OPERATION OF THERMAL DRYERS IN COAL PREPARATION PLANTS IN POUNDS PER 10^6 Btu

	Without(a) Controls	With Controls
SO_x	0.012	0.0002(b)
NO_x	0.006	0.006
Particulates	1.000	0.01(c)

(a) Data obtained from Reference N-6.
(b) Alkalis are used to remove 85 percent of SO_2.
(c) High energy venturi used at efficiency of 99.9 percent.

Water

Coal washing operations require large amounts of water. Table N-2 shows the amount of water used or discharged by coal preparation plants in 1962. The operation of jigging which is used in 50 percent of all coal washing operations requires 1500 to 2000 gallons of water per ton of coal processed.(N-8) Table N-2 shows that although 81 percent of the water was recirculated, more than 15 percent was discharged to the environment during that year. Furthermore, only 18 percent of the total water discharged was treated prior to disposal. This water usually consists of about 15 percent suspended solids consisting of fine clay and coal and a maximum of 1 percent dissolved solids.(N-1) If water obtained from acid mine drainage may be considered analgous to the discharged water, at least in a qualitative sense, then the dissolved solids consist mainly of the $SO_4^=$ ion in conjunction with the ions of iron, aluminum, calcium, magnesium, sodium, and potassium.(N-1)

Modern coal cleaning plants operate by total recirculation of water. However, in order to keep the total solids concentration below a critical value of 15 to 20 percent, blowdown is necessary. This, in addition to the water lost in the thermal dryers, is made up by fresh water drawn from water treatment plants to be described later.

Over the past decade there has been a marked increase in the production of coal by mechanical means. This has led to an increase in the amount of coal fines to be recovered, usually by froth floation. Up to 20 percent of plant feed may be processed in this fashion. The flow in this circuit is treated with surface-active organic compounds, such as alcohols or kerosene, to enhance frothability. The amounts may vary between 0.03 to 0.3 pound of alcohol per ton of solids processed.

TABLE N-2. WATER USAGE AT BITUMINOUS COAL AND LIGNITE PREPARATION PLANTS IN THE UNITED STATES, 1962, BY STATES(N-1)

State	Water Usage x 10^6 gal			Water Disposal x 10^6 gal	
	New Water	Recirculated Water	Total	Consumed	Discharged
Alabama	2,330	7,363	9,693	352	1,978
Alaska	1,344	132	1,476	3	1,340
California	18	18	36	10	8
Colorado	5	15	20	1	4
Illinois	5,304	22,409	27,713	427	4,877
Indiana	1,190	8,685	9,875	142	1,048
Kansas	147	1,715	1,862	101	46
Kentucky	8,096	14,623	22,719	535	7,561
Missouri	226	1,067	1,293	109	116
Montana	2	20	22		2
New Mexico	41	300	341	4	38
Ohio	645	7,091	7,736	290	355
Oklahoma	26	132	158	11	15
Pennsylvania	2,682	23,483	26,165	768	1,914
Tennessee	1		1		1
Utah	995	1,399	2,394	626	369
Virginia	1,593	8,010	9,603	278	1,316
Washington	18	25	43	4	14
West Virginia	7,169	42,024	49,193	2,028	5,141
Wyoming	1		1		1
TOTAL	31,833	138,511	170,344	5,689	26,144

Refuse piles resulting from the washing of coal may also be a source of water pollution in the absence of pollution controls. This may happen by oxidation of pyrite to sulfuric acid in the presence of oxygen and water. Surface runoff would subsequently act as carrier of the acid effluent to nearby streams.

The emission factors for the various sources of water contamination were estimated for the two cases in which environmental controls are or are not applied. The results are presented in Table N-3.

TABLE N-3. ESTIMATES OF WATER POLLUTION RESULTING FROM OPERATION OF COAL WASHING PLANTS IN POUNDS PER 10^6 Btu

	Without Controls	With(e) Controls
Suspended Solids	2.13(a)	0
Dissolved Solids	0.15(b)	0
Total Organic Materials	0.003(c)	0
Acid H_2SO_4	0.01(d)	0.001(f)

Footnotes for Table N-3:

(a) Assuming a concentration of 150 grams per liter and using water discharge and coal production data for W. Va. in 1962.

(b) Assuming a concentration of 10 grams per liter.

(c) This assumes an alcohol addition of 0.3 pound per ton of fines (20 percent) processed.

(d) Calculated on the basis of data given in References N-9 and N-10 and a 1,000 tph plant with 90 percent yield.

(e) Assumed 100 percent efficiency in control schemes unless otherwise noted.

(f) 90 percent removal by spreading and covering refuse pile. Reference N-10.

Solid Waste

This waste is an accumulation of sulfur-rich plant rejects resulting from the coal washing process. The amount of these rejects would depend on the specific gravity of separation used in the plant for steam coal. The rate of disposal of these rejects would be in the range of 10 to 21 pounds per 10^6 Btu of plant output. In addition to their impacts on the air and water environments, as previously discussed, these plant rejects represent a commitment of the land resource at the rate of 1 to 2 x 10^{-3} acre-hr/10^6 Btu. It is estimated that a modern 1,000 tph plant would require a land area between 40 and 90 acres. The upper part of the range may be required if lagooning or ponding of plant wastes are undertaken.

Pollution Controls

The installation of air and water pollution control equipment has recently become standard in coal washing plants which are either planned or recently completed.(N-7) As mentioned earlier, this is the result of enforcing more stringent state and federal regulations. The methods and costs of controls, to be described shortly, are those which have received at least some application in various locations. Although existing technology is capable of reducing emissions to acceptable levels, economic considerations seem to detract from the task of complete abatement.

Air

Since operation of thermal dryers is considered to be the main source of emissions to the air environment, recent efforts have been directed at minimizing this source. In one instance,(N-10) a high energy venturi scrubber was installed to remove particulates from gases exiting a fluidized-bed dryer capable of processing 500 tph of dried product. After scrubbing, the gases contained about 0.1 grain/cu ft of particulates. Although no mention was made of any lime additions to the scrub water, a SO_x removal of about 85 percent is possible by this technique. The costs associated with venturi scrubbing were estimated at 2.65 mils/10^6 Btu for a gas flow of 270,000 cfm and a production of 500 tons per hour.(N-11, N-10, N-6)

The gaseous emissions of SO_x, NO_x and hydrocarbons that may result from the burning of refuse piles can be effectively eliminated by the proper disposal of solid waste to be described later.

Water

The water discharged from coal preparation plants is very similar in chemical characteristics to that resulting from acid mine drainage. The main difference is the high concentration of suspended solids in the plant discharge. Treatment of this acid water involves neutralization with lime, the addition of flocculants, as alum, or ferrous sulfate, and subsequent aeration and ponding. Make-up water for the plant is obtained from the clear supernatant of the settling ponds. Contamination of ground and surface waters by percolation of effluent from the settling ponds should be minimal when they are properly designed.(N-12) The cost of lime treatment is highly variable.(N-13) Factors affecting this cost may be the acidity and quantity of the treated effluent and geographical location of treatment plant. The average cost of the treatment was estimated as 0.65 mil per 10^6 Btu of product coal.(N-15) This cost may, however, range between 0.1 and 1.30 mils per 10^6 Btu.(N-12)

As explained earlier refuse that has not been properly disposed of may become a source of acid water. In actual experiments conducted on a 2 million cubic yard pile,(N-10) it was found that acid water drainage amounted to 198 pounds (expressed as $CaCO_3$) per acre of pile per day. Employing disposal methods, to be described later, the drainage was reduced by 90 percent.

Solid Waste

The solid refuse resulting from coal washing plants can be disposed of in such a way as to minimize air and water pollution.(N-10) The methods employed in disposal have been discussed elsewhere.(N-10) Briefly, the procedures involve spreading and compacting the refuse, covering it with a layer of soil and revegetating with plants, such as grass. Fertilizers are usually added to the soil to expedite the vegetation process.

The costs of refuse disposal by methods as outlined above are highly variable. For a 1000 tpd plant with a refuse pile of 50 acres, these costs may range between 0.3 and 1.0 mil per 10^6 Btu. The factors affecting cost may be land topology and the availability of suitable cover material.

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APPENDIX O

CHEMICAL DESULFURIZATION OF COAL

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APPENDIX O

CHEMICAL DESULFURIZATION OF COAL

Summary

An alternative to combat air pollution created by the combustion of high sulfur coal is to remove the sulfur from the coal before combustion. One technique for sulfur removal, referred to as chemical desulfurization, would entail treating the coal with a reagent capable of converting the sulfur to a form which could be extracted or readily volatilized from the coal matrix.

The technical feasibility of producing low sulfur coal by chemical desulfurization has been established in bench-scale operations. The pyritic sulfur and approximately 50 percent of the organic sulfur were extracted from an Ohio coal by applying hydrothermal technology using an aqueous caustic solution as the leachant. Heating various coals in aqueous ferric salt solutions, in molten salt baths, and in a mixture of steam and air removed the pyritic sulfur, producing a coal containing only the organic sulfur. Subjecting various coals to hot leaching with organic solvents resulted in the removal of up to 80 percent of the organic sulfur. Leaching with organic solvents had no effect on the pyritic sulfur.

Emissions from chemical desulfurization processing will depend on the process employed. In general, sulfur emissions to the atmosphere are expected to be negligible. The majority of the emissions would be from the waste liquid effluents and solid by-products. For example, total emissions from the ferric salt leaching process were estimated at 4.7 pound per 10^6 Btu and, from the organic leaching process, 3.3 pound per 10^6 Btu. However, by employing resource recovery practices and by regenerating and recycling of the leachants, emissions could be further reduced.

Quantitative costs for chemical desulfurization of coal cannot be calculated because of the stage of development of this technology. Qualitatively, costs, based on scale-up of bench-scale data, are estimated to be approximately 13 cents per 10^6 Btu.

Assuming chemical desulfurization of coal is economically feasible, it is projected that approximately 10-15 years will be required to establish commercial feasibility. This time span could be reduced significantly if a concentrated effort is made to do so.

Technological Background

Types of Sulfur in Coal

Sulfur is an undesirable constituent of all coals. It is present in amounts ranging from traces to greater than 10 percent. The bulk of the commercial coals of the Eastern United States contain from 0.5 to 4.0 percent sulfur.(0-1)

Sulfur is present in coal as sulfate sulfur, organic sulfur, and pyritic sulfur. Sulfate sulfur is of minor concern as its concentration in coal is in the neighborhood of 0.1 percent. Sulfate sulfur is present as indiscrete particles of gypsum, with copperas ($FeSO_4 \cdot 7H_2O$) and in the mineral jarasite [(Na_1K), $Fe_3(SO_4)_2(OH)_6$]. The iron sulfates become important only in weathered coals and, like all sulfate sulfur, are a minor problem with respect to atmospheric pollution.

This cannot be said for the pyritic and organic sulfurs. Pyritic sulfur is found in coal as ferrous disulfide (FeS_2) in pyrite and/or marcasite. The two minerals have the same chemical composition but have different crystalline forms. Pyrite is the most commonly reported form of the two and is ubiquitous in coal.

Pyrite sulfur occurs in coal in many forms--veins, lenses, nodules, or balls, and pyritized plant tissue. The pyritic particles may be macroscopic in size which are visible to the naked eye or present as particles which can be seen only with the aid of a microscope. Much of the pyritic sulfur is present as microscopic particles, making physical desulfurization difficult. Concentration of pyritic sulfur varies from about 0.2 to over 8 weight percent, making up from 20 to 80 percent of the total sulfur content of coal.

The third form of sulfur in coal, organic sulfur, occurs as part of and linked into coal.(0-2) Concentration ranges from about 0.3 to about 2.4 weight percent, making up from 20 to about 85 percent of the total sulfur. According to Given and Wyss,(0-3) organic sulfur is found in coal in the following forms.

(1) Mercaptan or thiol, RSH

(2) Sulfide or thio-ether, RSR

(3) Disulfide, RSSR

(4) Aromatic systems containing the thiophene ring.

Supposedly, organic sulfur cannot be removed unless the chemical bonds holding it are broken. Thus, the amount of organic sulfur present defines the lowest limit to which a coal can be cleaned by physical methods.

Chemical Desulfurization

From an environmental viewpoint, one of the problems with coal as a fuel is its high sulfur content. Physical desulfurization is not entirely satisfactory as (1) some coals are not amenable to removal of the pyrite by physical means, (2) complete removal of pyrite is not possible, and (3) organic sulfur is not removed by physical methods. Thus, because of the high residual sulfur content of physically cleaned coals, consumers of coal are searching for innovative approaches to the production of low sulfur coal. One route which is being viewed extensively is the chemical desulfurization approach whereby the sulfur content of the coal is reduced to within acceptable limits by treating the coal with a reagent to react with or liberate the sulfur. Separation of the sulfur prior to combustion would then result in a low-sulfur coal which could be consumed directly with minimal pollution control of stack gases.

In the removal of sulfur prior to combustion, the majority of the effort has emphasized the reduction of pyritic sulfur as the organic sulfur is reportedly molecularly bound to the coal and is less subject to attack. Thus, the removal of the organic sulfur is more difficult.

Pyritic Sulfur Removal

Currently, chemical desulfurization of coal is not being practiced commercially. However, this area is and has been under study throughout the United States and in time chemical desulfurization is expected to become a reality. Presently, this work is in the experimental stage.

Pyrite (FeS_2) is found in coal as discrete nodules in heteregenous mixture and is therefore subject to attack by a wide variety of chemical reagents. These reagents are generally used in conjunction with elevated temperature coal treatment processes.

Chemical methods for leaching the mineral matter from coal using aqueous solutions of nitric acid, chlorine, hydrofluoric acid, and caustic have been reported to be successful.(0-4) One chemical method employed molten caustic (sodium/potassium hydroxide in a ratio of 1:1) at various temperatures to dissolve pyritic sulfur from conventionally cleaned Pittsburgh seam coal.(0-5) In this work, complete removal of pyritic sulfur was achieved by treating 1 part coal (minus 40 mesh) with 4 parts of caustic at temperatures between 150 to 250 C. Below 150 C, no removal of sulfur was achieved. At temperatures between 250 to 400 C, the extraction was rapid, requiring approximately 5 minutes. In this system, the organic sulfur is not attacked.

High temperature steam-air treatment has been reported to be effective in reducing the sulfur concentration. The treatment of Rumanian and Indian coals resulted in sulfur reductions of 30 percent and 56 to 58 percent, respectively. The addition of ammonia along with the steam resulted in the removal of 88 percent of the sulfur from the Indian coals.(0-5) The treatment of coal with steam and air at 150 to 200 psi and temperatures up to 250 F resulted in the removal of the pyritic sulfur which made up approximately 50 percent of the total sulfur. The organic sulfur was not touched.(0-6)

The treatment of coal with aqueous solutions is effective for the removal of pyritic sulfur and, depending on the leachant, for the removal or organic sulfur as well. Leaching of ground coal with aqueous solutions of ferric chloride or ferric sulfate (Figure 0-1) at temperatures up to 100 C has resulted in the extraction of the majority of the pyritic sulfur.(0-7) By this process, pyritic sulfur is converted to sulfate and elemental sulfur. A continuous countercurrent leaching operation may be employed. The elemental sulfur formed in the coal is separated from the coal matrix by vacuum distillation or extraction with a solvent such as toluene or kerosene. By-products from the process are sulfur and iron sulfate. Iron oxide is sometimes formed depending upon process conditions.

Leaching ground coal with aqueous caustic solutions under hydrothermal conditions has resulted in removal of all of the pyritic sulfur and approximately 50 percent of the organic sulfur. By this process, the sulfur in the coal is converted to a water-soluble form by treating the coal with sodium hydroxide solutions at temperatures greater than 100 C and steam pressure greater than one atmosphere.(0-8)

Other treatments such as the following are said to decompose pyrites and might be useful in treating coals.(0-3)

(1) Sodium bicarbonate and heavy metal carbonate in a sealed tube at 185 C.

(2) Steam at 300 to 400 C.

(3) Sulfur monochloride vapors at 140 C.

(4) Moist carbon dioxide at 250 C.

(5) Carbon tetrachloride at 250 C.

The use of chemicals in combination with somewhat higher temperatures has been found to be effective in reducing the sulfur content of coal. However, the final product is a "char" rather than coal.(0-9) For example, when 20- to 40- mesh size coal was treated for four hours at 1000 C in atmosphere of nitrogen, carbon dioxide, carbon monoxide, methane or ethylene, approximately 50 to 60 percent of the sulfur was removed. Treatment with (1) water gas removed 76 percent, (2) anhydrous ammonia removed 82 percent, (3) hydrogen removed 87 percent, and (4) steam removed 82 percent of the original sulfur present.

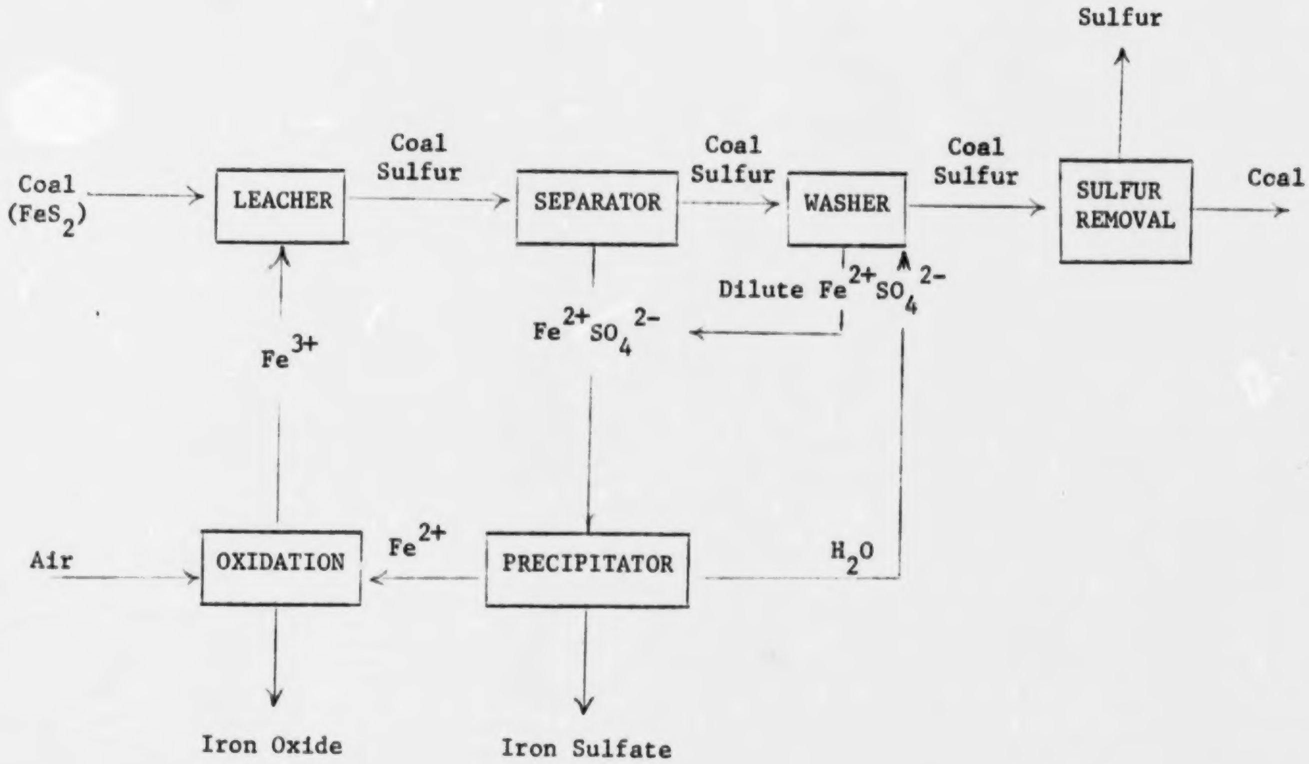
Coal
(FeS$_2$)
LEACHER
Coal
Sulfur
SEPARATOR
Coal
Sulfur
WASHER
Coal
Sulfur
SULFUR REMOVAL
Sulfur
Coal
Dilute Fe^{2+}SO$_4^{2-}$
Fe^{2+}SO$_4^{2-}$
Fe^{3+}
Air
OXIDATION
Fe^{2+}
PRECIPITATOR
H$_2$O
Iron Oxide
Iron Sulfate

FIGURE O-1. PROCESS FLOW CHART: (1) the coal is treated with aqueous ferric solution in a batch or countercurrent leaching unit; (2) the coal is separated from residual iron salts in a batch or countercurrent washing unit; (3) the elemental sulfur formed is removed by vacuum flash distillation, inert gas vaporization, or solvent extraction to give desulfurized coal; (4) the depleted ferric solution is air-oxidized, producing iron oxide, and (5) the regenerated ferric solution is recycled to the leaching unit.

State-of-the Art Technology Projection

Currently, there appears to be no commercial installation producing low sulfur coal by chemical desulfurization. However, from the current results of bench-scale research on the extraction of total sulfur (pyrite and organic), it is conceivable that commercial chemical desulfurization of coal will become a reality in a few years.

Bench-scale research has established the technical feasibility of the removal of pyritic sulfur from coal by chemical desulfurization. Estimated time span for subsequent development of this technology to commercial production is 9 to 11 years. This projection is based on a time span of 1 year for additional bench-scale research, 2 to 3 years for pilot planting, 3 to 4 years for construction and operation of a demonstration plant, and 3 years for construction of a commercial plant.

Current bench-scale research has resulted in the extraction of approximately 50 percent of the organic sulfur from coal. The task of removing the additional organic should be surmountable; thus, the projected time span for commercial production of a coal containing no pyritic sulfur and essentially no organic sulfur is 10 to 15 years (by 1982-1985). Achieving this goal will, of course, depend on the rate of effort. Assuming that a modest rate of effort is put forth, it is estimated that bench-scale technical feasibility can be established by about 1973 to 1975. Allowing 2 to 3 years for piloting of the process and another 3 to 4 years for design, construction, and operation of the demonstration plant, it is estimated that by about 1982 to 1985, commercial feasibility will be established. This projected time span could probably be reduced significantly if an all out effort were made.

Emissions

In 1969, the United States power industry discharged to the atmosphere about 7 million tons of sulfur in the form of SO_2. In the absence of controls other than tall stacks, the discharge in 1980 is estimated to be about 18 million tons of sulfur. Sulfur emissions control systems for the flue gases are about 75 percent efficient. Assuming all flue gases are controlled at the 75 percent level, sulfur emissions from power plants are estimated to be about 4.5 million tons by 1980.

These levels of sulfur emissions explain why there is an intensified search for new or improved technology for removal of sulfur from coal before combustion. Achievement of this goal would reduce sulfur emissions from power plants to practically zero.

Chemical desulfurization offers one potential solution to the sulfur emissions problem now facing the United States. Removal of all or a major part of the sulfur from coal prior to combustion will result in a fuel which can be used with a low atmospheric pollution potential. Sulfur emissions would be negligible. Levels of other types of emissions such as the toxic metals may be reduced significantly, depending on the process employed.

The majority of the emissions to the environment to be expected from chemical desulfurization operations will be in the form of aqueous effluents and solid wastes. Quantities and types will depend on the process employed and the degree of resource recovery which can be implemented. At this stage of development, the environmental impact of employing chemical desulfurization of coal cannot be calculated on a quantitative basis, only on a qualitative basis. This is because the chemical desulfurization scheme is at the bench-scale state of development. However, the probability of a low environmental impact appears high.

The ferric salt leaching process as shown in Figure O-1 contains the following probable sources of wastewater, air pollution, and solid wastes:

1. Spent leach solution from the leaching circuit.

2. By-product iron sulfate from the leaching circuit.

3. Elemental sulfur from the sulfur recovery circuit.

4. Solvent-vapos loss from the sulfur recovery circuit.

No firm data are available at this time to project accurately the quantities of the effluent streams. The estimates given below are based on assumptions as indicated.

Spent Leach Solution

The process claims to regenerate the leach solution by air oxidation of ferrous iron to ferric iron and recycle of the regenerated solution within the leaching circuit. However, continuous build-up of impurities extracted from the coal, such as certain ash components and water soluble organic compounds, suggests the need for removing a part of the leach solution from the circuit as waste. The quality of this wastewater stream will depend upon the quantity of impurities generated and the extent to which the impurities are allowed to build up in the leach solution. Based on an assumption that the impurities are produced at a level equivalent to 0.5 percent by weight of coal feed and the impurity concentration is allowed to build up to 10 percent by weight in the leach solution, the wastewater effluent from the leaching circuit is estimated as follows.

Basis: 1 ton of coal processed

$$\text{Waste leach solution} = \frac{(1)(0.005)}{0.1} = 0.05 \text{ ton waste/ton coal}$$

Iron Sulfate

Iron sulfate and elemental sulfur are produced from the leaching circuit during regeneration of the leach solution. These materials could be sold, if a suitable buyer could be found, or must be disposed of by some other means. The quantities of these materials produced from the process were estimated by overall sulfur and iron balance calculations as follows.

Basis: 1 ton of coal processed
89 percent removal of pyritic sulfur
40 percent of sulfur removed is converted to elemental sulfur
60 percent of sulfur removed is converted to sulfate

Input
Total sulfur: 0.03 ton
Pyritic sulfur: 0.02 ton
Sulfate sulfur: 0.002 ton
Organic sulfur: 0.008 ton
Fe in FeS_2: $\frac{(0.02)\ (55.8)}{(2)\ \ (32.1)} = 0.017$ ton

Output (assuming 89 percent removal of pyritic sulfur)
Total sulfur removed from coal: 0.0178 ton
Sulfur converted to elemental sulfur: 0.0178 (0.4) = 0.0071 ton
Sulfur converted to $FeSO_4$: 0.0178 (0.6) = 0.011 ton
Total $FeSO_4$ produced: 0.011 ton $\left[\frac{152}{32.1}\right]$ = 0.052 ton
$FeSO_4$ removed with waste leach solution: 0.05 ton (15%) = 0.0075 ton (assuming 15 percent $FeSO_4$ in the leach solution)
$FeSO_4$(7) (solid) produced: 0.052 ton - 0.0075 ton = 0.045 ton

Elemental Sulfur

Sulfur balance calculations shown above indicate that elemental sulfur is produced at a rate of 0.0071 ton per ton of coal processed. The sulfur produced is claimed to have a 99.9 percent purity, indicating a potential return from the sale of the recovered sulfur.

Summary of Emission Estimates

Estimated quantities of effluents from the process are summarized in Table O-1.

TABLE O-1. EMISSIONS FROM PYRITIC SULFUR REMOVAL PROCESS

Basis: 1 ton of coal, 3.0%S, 2.0% pyritic
Heating Value: 12,000 Btu/lb

Effluent		Total, lb	Emission Factor, lb/10^6 Btu
Wastewater[(a)]		100	4.20
Solids:[(b)]	Elemental Sulfur	14.2	0.59
	$FeSO_4$	90	3.75

(a) Containing 15 percent by weight of $FeSO_4$ and additional 10 percent by weight of various inorganic and organic compounds extracted from coal.

(b) These solids have a market potential. In this case, they would not be considered pollutants.

Process Economics

Although the feasibility of applying chemical desulfurization technology for producing low sulfur coals has been established, the scale of operation has not been large enough to obtain accurate cost estimates on any of the processes and cost estimates on some of the process would be meaningless until further experimental work is conducted. However, to obtain preliminary costs for comparison with other processes for producing low sulfur fuels, economics of ferric salt leaching to remove pyritic sulfur were estimated.

Ferric Salt Leaching(O-10)

By this process (Figure O-1), aqueous ferric solution at 100 C selectively oxidizes the pyritic sulfur content of coal to form free sulfur (with part of the sulfur content being oxidized to sulfate which dissolves in the aqueous solution). The aqueous solution is separated from the coal, and the coal is washed to remove residual iron salts. The free sulfur may then be removed from the coal matrix by steam or vacuum vaporization (or solvent extraction with toluene or kerosene), and the oxidizing agent may be regenerated in any number of ways, including air oxidation of ferrous ion to ferric ion (Eq. O-3). The resulting coal is basically pyrite-free and may be used as low-sulfur fuel. The chemistry is outlined in Eqs. O-1 through O-3.

$$2Fe^{3+} + FeS_2 \rightarrow 3Fe^{2+} + 2S \qquad (O\text{-}1)$$

$$S \cdot coal \rightarrow S + Coal \qquad (O\text{-}2)$$

$$3Fe^{2+} + 3/2[O] \rightarrow 3Fe^{3+} + 3/2[O^{2-}] \qquad (O\text{-}3)$$

Since "iron is used to remove iron", on regeneration it is not necessary to separate the iron, which is extracted from the coal, from a metal oxidizing agent.

Total cost for installation of unit for processing 100 tons/hour of coal is estimated at $4 million.

Operating costs are estimated at $1.95/ton of coal. This brings total cost to about 8 cents/million Btu (0.083 cent/kwhr).

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APPENDIX P

PRODUCTION OF SYNTHETIC HYDROCARBON LIQUIDS FROM COAL (LIQUEFACTION)

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APPENDIX P

PRODUCTION OF SYNTHETIC HYDROCARBON LIQUIDS FROM COAL (LIQUEFACTION)

Summary

Currently there are seven processes that have as their main objective the production of liquid hydrocarbons from coal. These are:

1. Fisher - Tropsch Synthesis
2. Pittsburg and Midway Coal Co. - Solvent Refined Coal Process
3. Consolidated Coal Company - Solvent Refining and Hydrogenation Process
4. Hydrocarbon Research Incorporated - H-Coal Process
5. Project Seacoke Process
6. COED Process
7. University of Utah - Intermediate Coal Hydrogenation Process

These seven processes are in various stages of development with the Solvent Refined Coal Process being the most advanced and the Intermediate Coal Hydrogenation Process being the least advanced. Two pilot plants (6 and 50 ton/day plants) have recently been announced to demonstrate the SRC process.

The Solvent Refined Coal process can produce an ashless, low-sulfur product of sufficiently high quality and Btu content that it can be substituted for coal, or when used in liquid form, fuel oil. The product as now conceived can produce fuel having 16,000 Btu/lb, 0.6 percent sulfur, and 0.05 percent ash.

Typical emission factors arising from a 222 x 10^9 Btu/day (about 950 MW) Solvent Refined Coal plant are compiled with others in the body of the report. Pittsburg and Midway Coal Company estimated the cost of the solvent refining step (i.e., the cost of the process exclusive of the cost of the feed coal) to be:

1. 30 cents/10^6 Btu (based on 20 year amortization)
2. 43 cents/10^6 Btu (based on 5 year amortization)

The cost of coal has not been included in the calculations because it varies from one plant situation to another. The total product selling price can be developed by adding to the above prices the coal cost in cents per million Btu multiplied by a factor of 1.33. This factor takes into account the 75 percent overall fuel efficiency of the process. Of the 30 cents/10^6 Btu cost figure (20 year amortization), all costs would be attributed to pollution control since the process was developed as a means of obtaining a clean burning fuel. Pollution control costs for a SRC plant located adjacent to the power station including coal loss would range as follows:

Coal Cost $/ton	20-Year Amortization, cents/10^6 Btu	5-Year Amortization cents/10^6 Btu
0 (Processing Cost)	30	43
3	34	47
8	41	54
12	47	60

The above costs were estimated on the basis of a process design study and have yet to be verified at the pilot-plant level.

Technology

The production of liquids from coal can follow one of four general paths: (a) production of a hydrogen-carbon monoxide mixture from coal, followed by catalytic synthesis of hydrocarbons (variations of the Fischer-Tropsch process); (b) solvent refining (essentially dissolving of coal with minimum hydrogenation to produce a low-ash and low-sulfur heavy bottoms product; (c) pressure hydrogenation of coal from the approximate composition $CH_{0.75}$ to nearer $CH_{1.0}$ using H_2 or H_2-CO mixtures (variations on the Bergius or Pott-Broche processes); and (d) staged pyrolysis (heating to drive off volatile elements) to minimize the residue. The last of these methods produces gas as well as liquid products.

Currently, there are seven processes that have as their main objective the production of liquid hydrocarbons from coal. These are:

1. Fischer-Tropsch Synthesis

2. Pittsburgh and Midway Coal Co. - Solvent Refined Coal Process

3. Consolidated Coal Company - Solvent Refining and Hydrogenation Process

4. Hydrocarbon Research Incorporated - H-Coal Process

5. Project Seacoke Process

6. COED Process

7. University of Utah - Intermediate Coal Hydrogenation Process

These seven processes are in various stages of development with the Pittsburg and Midway Solvent Refined Coal Process being the most advanced and the Intermediate Coal Hydrogenation Process (Utah State University) being the least advanced. The latter is included only for completeness and has not yet been thoroughly researched on the bench scale. The Fischer-Tropsch process is included in the above list for historical purposes. The major products from this process are gasoline, diesel fuel, waxes, and a wide spectrum of organic chemicals. The process makes very expensive products by American standards, and is generally considered unattractive in the United States.

A very detailed review of the available technical literature regarding the above processes has been performed by Hottel and Howard(P-1) and Schurr.(P-2) Details of these reviews will not be reproduced here. Emphasis in the present work will be placed on the Pittsburg and Midway Solvent Refined Coal Process. It is, in Battelle's judgment, the furthest along in development for commercial application and seems well suited to the needs of the electric utility industry. Two pilot plants for studying the process have recently been announced.(P-3,P-4) A six-ton per-day pilot plant for studying the steps in the Solvent-Refining Process will be built at the Southern Electric Generating Company's Ernest C. Gaston plant.(P-4) Funding for the project will come from the Edison Electric Institute ($4 million) and Southern Company's operating affiliates ($2 million). Groundbreaking ceremonies for a 50-ton-per-hour plant at Tacoma, Washington, were held on October 27, 1972.(P-3) Funding for this project will come from the Office of Coal Research.

Pittsburg and Midway Solvent-Refined Coal Process

Solvent refining was initiated with the limited objective of producing a low-cost antipollution alternative to residual oil and natural gas for use in boilers. Since the process is not primarily designed to produce lighter oil products, only limited hydrogenation is required. The hydrogenation step is followed by ash separation and conversion of sulfur to a removable form. The original laboratory development of the chemical process involved was carried out by Spencer Chemical Corp. (now Pittsburg and Midway Coal Mining Company) and an economic evaluation of a full-scale plant has been published.(P-5) More recently Process Research, Incorporated(P-6) updated this work.

The process can use any rank coal, from lignite to low-volatile bituminous. The Solvent Refined Coal process is illustrated in Figures P-1 and P-2. Using the process, an ashless, low-sulfur fuel having a heating value of about 16,000 Btu per pound can be produced from coal. The fuel product is produced by dissolving coal in a coal-derived solvent in the presence of hydrogen at a pressure of 1,000 psi or greater and a temperature of 825 F.

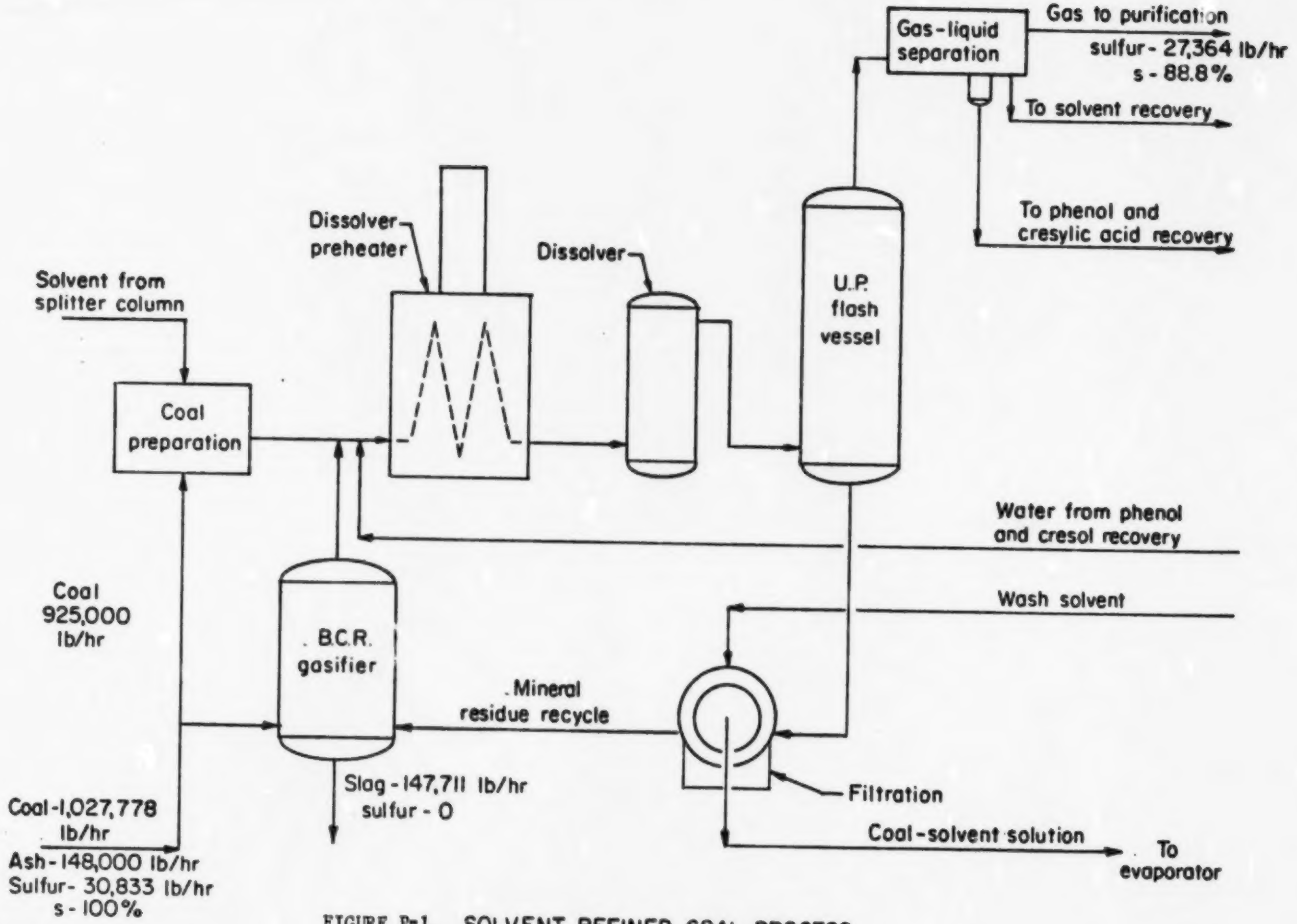
Gas-liquid separation
Gas to purification
sulfur - 27,364 lb/hr
s - 88.8%
To solvent recovery
To phenol and cresylic acid recovery
Dissolver preheater
Dissolver
U.P. flash vessel
Solvent from splitter column
Coal preparation
Water from phenol and cresol recovery
Wash solvent
Coal 925,000 lb/hr
B.C.R. gasifier
Mineral residue recycle
Filtration
Slag - 147,711 lb/hr
sulfur - 0
Coal - 1,027,778 lb/hr
Ash - 148,000 lb/hr
Sulfur - 30,833 lb/hr
s - 100%
Coal-solvent solution
To evaporator

FIGURE P-1. SOLVENT REFINED COAL PROCESS
Basis: 3.0% Sulfur; 14.4% Ash; 12,000 Btu/lb
222 MMM Btu/day Capacity (950 mw)

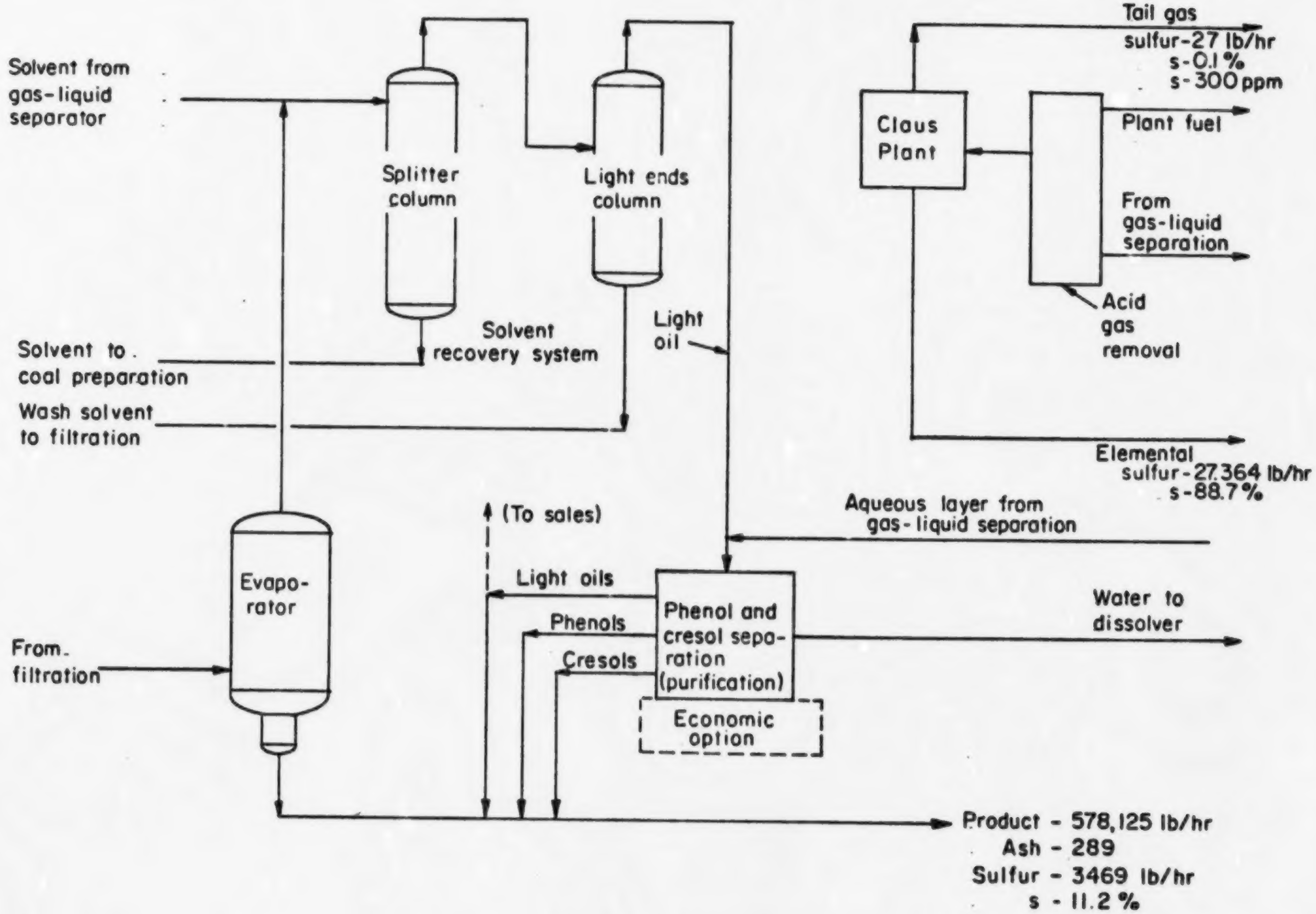
Solvent from gas-liquid separator
Splitter column
Light ends column
Solvent recovery system
Solvent to coal preparation
Wash solvent to filtration
Light oil
Evaporator
From filtration
(To sales)
Light oils
Phenols
Cresols
Phenol and cresol separation (purification)
Economic option
Claus Plant
Acid gas removal
Tail gas
sulfur-27 lb/hr
s-0.1%
s-300 ppm
Plant fuel
From gas-liquid separation
Elemental
sulfur-27,364 lb/hr
s-88.7%
Aqueous layer from gas-liquid separation
Water to dissolver
Product - 578,125 lb/hr
Ash - 289
Sulfur - 3469 lb/hr
s - 11.2%

FIGURE P-2. SOLVENT REFINED COAL PROCESS
Basis: 3.0% Sulfur; 14.4% Ash; 12,000 Btu/lb
222 MMM Btu/day Capacity (950 mw)

The coal-solvent solution is then filtered and evaporated to yield the fuel product with ash and sulfur both substantially removed. The fuel product can be utilized as either a liquid or solid.

Initially, the coal is crushed to 1/8 inch or less and dried to a moisture content of 3 percent. It is then fed to a slurry mix tank where it is mixed with an anthracene oil at a temperature of about 300 F to form a slurry. The coal-solvent slurry is then pumped through a line where synthesis gas (a mixture of methane, hydrogen, carbon monoxide, and carbon dioxide) is added.

The coal-solvent slurry and synthesis gas are pumped through the dissolver preheater into the dissolver. The coal depolymerization and dissolving process begins in the preheater where the material goes through a gel stage. Dissolving is completed in the dissolver. Simultaneously introduced into the preheater is a water stream recycled from the phenol and cresol separation section of the plant.

As a result of the solution and hydrogenation reactions which occur in the dissolver, hydrocarbons, H_2S, heavy oils and CO_2 are formed. The total product stream flows from the dissolver to the high pressure flash vessel in which vapor and liquid are separated. The vapor stream, containing light hydrocarbons, phenols, cresols, water vapor, H_2S, CO_2 and fuel gas, is fed to the gas-liquid separation section of the plant. After further pressure reduction, the liquid stream is fed to rotary pressure filters.

The filters remove ash and undissolved carbon from the coal-solvent solution. The filter cake is washed with light solvent to remove coal-solvent solution. The remaining mineral residue, containing about 70 percent ash and 30 percent carbon, is then recycled to the coal gasifier.

The coal-solvent solution is then fed to the vacuum flash evaporator where it is flashed at 625 F to separate the liquid coal from the anthracene oil and light solvent. The flashed anthracene oil wash solvent, light hydrocarbons and dissolved gases are condensed and fed to the solvent recovery unit. The liquid coal, with light oil blended back in, is then ready for fuel use. It can be fed as a hot liquid directly to an on-site user or it can be solidified for shipment to a distant use point.

In the gas-liquid separation section of the plant, three streams are isolated for further processing. A gas stream, consisting of H_2S, CO_2 methane and other gases, is fed to the acid gas removal system. A hydrocarbon-rich stream is combined with the vacuum flash evaporator condensate and fed to the solvent recovery system. A water-rich stream containing phenols and cresols is fed to the phenol and cresol separation unit.

In the acid gas removal system, CO_2 and H_2S are separated from the gas stream and sent to a Claus unit (and tail gas treatment system) where the H_2S is converted to elemental sulfur. The other gases, with 99.9

percent of the H_2S removed, are used for plant fuel.

In the solvent recovery system, the solvent mixture is first fed to the wash solvent splitter column. In this column, wash solvent and lighter material are boiled off overhead to the light ends column, leaving the anthracene oil for recycle to the coal preparation system.

The wash solvent and other light materials are fed to the light ends column. In this column, light oil is boiled off leaving the wash solvent for recycle to the rotary pressure filters. The light oil flows to the phenol and cresol separation unit, if economics dictate such a unit, otherwise only a water-light oil separation unit will exist.

In the phenol and cresol separation unit, phenols and cresols are removed from the light oil and from the water-rich stream coming from gas-liquid separation. The phenols and cresols are blended back into the liquid coal product. The light oil can be blended into the liquid coal product also, or it can be sold directly as a by-product. The water is recylced to the preheater.

Process Research, Inc. performed a conceptual design study on a 222 billion Btu per day Solvent Refined Coal Plant(P-6), i.e., for a plant large enough to supply fuel to a 950 MW power station. The material balance is shown in Table P-1 and on the flowsheets (Figures P-1 and P-2). The above plant Btu output is based upon producing a single product with phenols, cresols, and light oil included as part of the product. The feed material basis is bituminous coal having 3.0 percent moisture, 14.5 percent ash, and 3.00 percent sulfur. The fuel product contains 0.6 percent sulfur and 0.05 percent ash.

TABLE P-1. MATERIAL BALANCE INFORMATION-
SOLVENT REFINED COAL PROCESS
AT 222 10^9 Btu/DAY
PLANT CAPACITY (950 MW)

	Eastern Coal(a)
Input, tons/hr	
Coal	514
Energy, Btu/hr	12.35×10^9
Output, tons/hr	
SRC	289
Slag	73.9
Sulfur	13.7
Tail Gas Sulfur	--
Coal Consumed	225
Heat	9.25×10^9
Overall Fuel Efficiency, percent	75

(a) Typical eastern coal having 3.00% S, 14.4 Ash and 12,000 Btu/lb.

Emissions

For the material balance shown in Table P-1, estimated emission arising from the Solvent Refined Coal process are presented in the module data sheet.

Air

Typical process air emission were estimated using EPA emission factors(O-7) for NO_x, CO, particulate matter, and total organic matter. The principal air emissions arising will be NO_x and CO obtained from consumption of coal (in the form of fuel gas) in the process to fulfill the required heat balance. There will, of course, be some sulfur emissions, expected in the form of sulfur dioxide, in a tail gas released during the gas purification and sulfur removal step. In the process sulfur is removed and recovered using Claus plant technology, backed up if need be by a tail gas treatment plant using one of several processes available. For the purposes of this discussion it was assumed that the Claus plant used in the process would be equipped with the latest advances in tail gas treatment. Sulfur recovery efficiency would, therefore, be 99.9 percent and only 27 pounds per hour of sulfur as SO_2 would be emitted to the atmosphere. The tail gas being emitted to the atmosphere would contain approximately 300 ppm (about 0.02 grain per scf) of sulfur.

Water

Water emissions from the plant should be minimal. In a well designed plant, closed-loop cooling would be employed and maximum use made of cooling towers and air coolers. Process water would be required mainly as a raw material for its hydrogen content in the BCR gasifier. However, all process water not used as a raw material would be recycled. There will, of course, be some concentrated blowdown streams from boilers and cooling towers to be disposed of. These should not be significant and arise from dissolved and suspended solids in the raw material water coming into the plant.

Solid Waste

There will be at least one solid waste stream arising from the Solvent Refined Coal Process. This is a process slag of about 73.9 tons/hr from the BCR gasifier and consists mainly of the ash removed from the solvent refined coal product. Elemental sulfur will also be recovered (13.7 tons/hr). If this could not be sold it would constitute a solid waste, or perhaps better considered a storable resource. For the design study performed, elemental sulfur would amount to 13.7 tons/hr.

Land Use

It is estimated that a 222 MMM Btu/day Solvent Referred Coal plant (about

950 MW) will require a site about 750 acres in size for the plant, the associated coal storage piles, and a solid waste disposal area for the resultant slag. In estimating the land area required for slag (solid waste) disposal, the basis considered was a 20-year plant life, 1 x 10^7 tons, and an average slag depth of 10 feet.

Other

It is possible that by-products could be recovered and sold. In addition to sulfur, such materials as cresols, phenols, and light oil could be recovered under certain attractive commercial conditions and sold as chemicals. If not, they would have to be blended into the product and sold as fuel. As previously mentioned, it is also possible that sulfur could be sold. Alternatively, it would have to be disposed of as a dry landfill.

Pollution Controls

Methods

The Solvent Refined Coal process is itself a pollution control method and represents an alternative to flue gas cleaning for fly ash and sulfur removal from coal.

In the process, no aqueous waste waters are discharged to the environment, and all contaminated waters are recycled. In this sense, it would appear to be superior to flue gas cleaning processes based upon absorption technology which use fairly liberal quantities of water and give rise to sludges which are often ponded for indefinite periods.

The ash in the coal is removed as a slag from the BCR gasifier and the refined product contains about 0.05 percent ash. When this fuel is burned with 20 percent excess air in a power station, for example, the particulate content of the flue gas would be about 0.02 grain per standard cubic foot (0.03 lb Ash/10^6 Btu) and, therefore, would not require any treatment for particulate removal, since it would easily meet pollution control standards. By way of comparison, post-combustion processing removes ash partially as bottom ash off the boiler and fly ash in a particulate control device, i.e., in an electrostatic precipitator, scrubber, fabric filter, etc. In a post-combustion removal process burning coal having the composition shown in Table P-1 in 20 percent excess air, the particulate control device would have to be approximately 99.6 percent efficient to achieve an outlet flue gas loading of 0.02 grain per standard cubic foot, i.e., to achieve a dust loading equivalent to that of burning Solvent Refined Coal.

Similar to gasification processes, sulfur is removed from the coal in the SRC process by hydrodesulfurization, i.e., by treatment with hydrogen and recovery of the evolved H_2S as elemental sulfur in a Claus process with tail gas treatment if necessary. The currently obtainable level of sulfur in the product is about 0.6 percent. In the Claus process, H_2S is combusted under precisely controlled conditions so that one-third of it is converted to SO_2. The cooled combustion products are catalytically reacted to form elemental sulfur

$$2H_2S + SO_2 \overset{Cat}{\rightleftarrows} 3S + 2H_2O$$

after which the sulfur is condensed and separated. However, recovery is not complete even with three converters, and as much as 5 percent of the entering sulfur is contained in the exit (tail) gas. Recently developed tail gas treating technology, e.g., the Beavon, Cleanair, and IFP processes, achieves recovery of almost all of the remainder. Consequently, sulfur removal of 99.5 to 99.9 percent is achieved on the incoming H_2S.

Since the process is only now planned for pilot testing at a modest scale(P-3,P-4), it is still speculative whether the process can achieve the 0.6 percent sulfur level in the product in large quantities on a routine basis. If this can be done, then burning SRC product in a power station would achieve a sulfur level of approximately 400 ppm SO_2 in the flue gas with no additional treatment (i.e., assuming 20 percent excess air for combustion). This would be equivalent to about 0.75 lb $SO_2/10^6$ Btu of SRC burned. Such a level would meet the current EPA standard of 1.2 lb $SO_2/10^6$Btu. If the standard became more stringent, it is conceivable that the sulfur level in the SRC product would have to be decreased. By way of comparison to flue gas desulfurization processes (3 percent sulfur coal with a heating value of 12,000 Btu/lb), the flue gas desulfurization process would have to remove 85 percent of the sulfur to achieve the 0.75 lb $SO_2/10^6$ Btu level attainable from burning SRC product (i.e., go from about 5 lb $SO_2/10^6$ Btu with no control when 3 percent sulfur coal is burned to 0.75 lb $SO_2/10^6$ Btu with the SRC product).

Effectiveness and Cost

Estimating reasonably accurate pollution control costs for the Solvent Refined Coal process is extremely complicated since the process is only now planned for pilot testing on a large scale. The assumption is made that solvent refined coal can be substituted for any of the other fuels without difficulty and is itself a pollution control strategy. The cost to utilities of achieving pollution control through the substitution of solvent refined coal for currently burned conventional fuels will depend on the price at which solvent refined coal is available locally relative to that of other fuels.

Jimeson(P-8) attempted to estimate pollution control costs in 1966 based on little pilot-plant data. Jimeson's cost estimation technique was as follows. First, the cost of solvent refined coal was determined at four selected plant locations scattered over the United States. Second, the transportation cost of distributing the refined product to each state was added to obtain the delivered price of solvent refined coal in each.

Third, the delivered price was compared to the price of fuels currently being burned in power plants in each state. The difference represented the cost of air pollution control achieved by sutstituting refined coal for presently burned contaminated fuels in existing power plants. Also since solvent refined coal can be melted and pumped to a burner in the same manner as a residual oil, the expense of the coal handling and feeding mechanism, the grate, and the ash disposal equipment common to coal-fired units can be conserved. Credits equal to these savings in capital, maintenance, and operating costs were then applied to new plants burning SRC.

Jimeson estimated processing costs (in terms of 1966 dollars) range between 18.8 and 19.2 cents per million Btu's. The price of solvent refined coal at the plants ranged from 27.1 to 32.4 cents per million Btu's for coals costing between \$1.30/ton (8.3 cents/10^6Btu) and \$2.97/ton (13.2 cents/10^6Btu) at the mine. The average cost of pollution control, through replacement of coal used by the utility with solvent refined coal in existing power stations was estimated to range from 4 to 29 cents/10^6 Btu. Expressed as a national average the estimated cost was 14 cents/10^6 Btu. Jimeson also estimated costs for new plants taking credit applied when SRC is used. These estimates were even more optimistic.

New cost estimates were made in 1970 by Pittsburg and Midway(P-5) and later reported by Process Research, Inc.(P-6) The P&M estimate indicated a commercial 222 billion Btu per day capacity plant will cost about \$80 million. Two selling prices (processing costs) of the product were computed not including the cost of feed coal. The prices reported are:

Based on 20 year amortization	30 cents/10^6 Btu
Based on 5 year amortization	43 cents/10^6 Btu

These prices were based upon the "Office of Coal Research Tentative Standards for Cost Estimating of Investor-Owned Plants for Producing Pipeline Gas from Coal". Constants used in the computations are:

Gross return	9 percent of rate base
Debt financing	65 percent of rate base
Interest cost	7.5 percent of rate base
Federal income tax	48 percent of rate base

The cost of coal was not included in the calculations because it varied from one plant situation to another. The total product selling price at the plant can be developed by adding to the above prices the cost in cents per million Btu multiplied by a factor of 1.33. This factor takes into account the 75 percent overall fuel efficiency of the process.

The pollution control cost (P) in cents/10^6Btu for a SRC plant located adjacent to the power station (including coal losses) can be estimated by the equations:

$$P = 1.33\ A + 30 \qquad \text{(20 year amortization)}$$
$$P = 1.33\ A + 43 \qquad \text{(5 year amortization)}$$

where A is the cost of feed coal in dollars per ton and the coal has the composition shown in Table P-1. For this simplified case, typical pollution control costs would range as follows:

Coal Cost, \$/ton	20 Year Amortization, cents/10^6 Btu	5 Year Amortization, cents/10^6 Btu
0 (processing cost)	30	43
3	34	47
8	41	54
12	47	60

This can be compared to flue gas cleaning which ranges between 11.3 to 79.0 cents/10^6 Btu.

Areas of Uncertainty

In the period 1962 through 1964, the process was studied in a batch autoclave and in a 1 pound per hour continuous bench-scale unit. In 1964 a continuous 2-ton per day process development unit was started and operated until 1965. Process Research Inc.(P-6) reports that the longest single continuous run lasted about one month. Currently the SRC process is being planned for pilot testing in both 6 and 50 ton/day plants. The Ft. Lewis, Washington, pilot plant (50 ton/day) is expected to be completed by late 1973. Developmental operations are expected to require 2 to 3 years for completion.

The following technical problems remaining are reported by Process Research, Inc.(P-6) It is expected that test work in the Ft. Lewis pilot plant will focus on the following:

1. Verify the process economics, since currently they are based solely on the bench-scale data.

2. Determine the adequacy of the materials of construction for each vessel in the process. The current estimated capital cost for the commercial scale plant is based on use of carbon steel and low alloy steel. If pilot-plant study shows that these materials are inadequate from a corrosion standpoint, then the initial plant investment could be significantly increased. At present, the developers are working to determine the lowest feasible grades for construction materials.

3. Study operating parameters in the dissolver to reduce the amount of sulfur in the product.

4. Study the optimum method of solidifying the product to permit marketing.

5. Determine the actual necessity for the two-column distillation system now conceived for solvent separation.

6. The filtration step in the process will require study to assure high recovery of wash solvent and to determine the performance of filter seals and bearings when operating at high temperature and pressure. This could be very important to process economics.

Not to be studied at the pilot plant, but under consideration is:

7. The suitability of the high-pressure slagging coal gasifier as a means of producing the necessary synthesis gas. If the gasifier is found unsuitable, the synthesis gas can be produced by steam reforming of product gases or by partial oxidation of the light oil. However, in that case, disposal of the mineral residue consisting of 70 percent ash and 30 percent carbon would then become a serious problem.

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APPENDIX Q

COAL GASIFICATION

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APPENDIX Q

COAL GASIFICATION

Summary

The gasification of coal is a technique to change the form of coal from a solid to a gaseous fuel. Two types of classes of processes are being developed: those that produce a low heating value fuel gas (100 to 500 Btu/ft^3 STP) and those that produce a high heating value product, equivalent to that of natural gas (about 1,000 Btu/ft^3 STP).

Present coal gasification processing alternatives may be characterized as those that add oxygen (either pure or as air) to the gasifier, those that add hydrogen, and those that use an externally fired circulating heat carrier. There are many variations on the general coal gasification process scheme. Consequently, for use in this analysis, four processes were considered:

(1) Low Btu gas

   (a) Lurgi process
   (b) Two-Stage Coal Combustion process (molten iron combustion)

(2) High Btu gas

   (a) Hygas process
   (b) CO_2 Acceptor process.

Selection of these processes corresponds to two options. Processes that produce low Btu gas would be located in close proximity to the power plant that use the fuel gas. Thus in this option, coal would still be transported to the utility site. Processes that produce high Btu gas would be located at the coal source and the product gas would be transported by pipeline to the utility. High Btu gas would also be used for space heating and industrial applications.

Typical emissions estimated for gasification plants of approximately 250 x 10^9 Btu/day for each of the above processes are given in the module data sheets in Appendix A of this report. Estimates for the cost of pollution control (i.e., the cost of the process exclusive of the cost of feed coal and transportation) are:

Low Btu gas - about 30¢/10^6 Btu
High Btu gas - 30 to 50¢/10^6 Btu.

Technology

The gasification of coal is a technique to change the form of coal from a solid to a gaseous fuel. Two types of classes of processes exist, those that produce a low heating value fuel gas (100 to 500 Btu/ft^3 STP) and those that produce a high heating value, equivalent to that of natural gas (about 1,000 Btu/ft^3 STP). The latter is often referred to as SNG (substitute natural gas) or "pipeline" quality gas.

In the production of low Btu fuel gas, the basic gasification process consists of reacting steam with coal at elevated temperatures. The main reaction occurring is:

$$C + H_2O \rightleftarrows CO + H_2 \qquad \text{(Q-1)}$$

This reaction is endothermic, the heat for this reaction being supplied by combusting a portion of the coal in air or oxygen:

$$C + 1/2\ O_2 \rightleftarrows CO \qquad \text{(Q-2)}$$

$$C + O_2 \rightleftarrows CO_2 \qquad \text{(Q-3)}$$

In addition, the water-gas shift reaction occurs

$$CO + H_2O \rightleftarrows CO_2 + H_2. \qquad \text{(Q-4)}$$

In the production of pipeline quality gas from coal in addition to the above, the basic reactions may be summarized as follows:

$$\text{Coal} \rightarrow C\ (\text{Char}) + CH_4 + \text{a mixture of liquids and gases} \qquad \text{(Q-5)}$$

$$C + 2H_2 \rightleftarrows CH_4. \qquad \text{(Q-6)}$$

Equation (Q-5) represents the devolatilization of coal. The mechanisms for the production of methane can be illustrated by Equation (Q-6), which is exothermic, or by a combination of Equations (Q-4) and (Q-1) to give

$$C + 2H_2O \rightleftarrows CO_2 + 2H_2, \qquad \text{(Q-7)}$$

which may be combined with Equation (Q-6) to give

$$2C + 2H_2O \rightleftarrows CO_2 + CH_4 \qquad \text{(Q-8)}$$

Whether high Btu gas or low Btu gas is produced depends upon the conditions (temperature, pressure, residence time, etc.) in which the gasifier is operated and the methanation step in the processes.

Present gasification processing alternatives may be characterized as those that add oxygen or air to the gasifier, those that add hydrogen, and those that use an externally fired, circulating heat carrier. Most processes use the first technique. A generalized flowsheet for most coal gasification processes for producing either low Btu or high Btu fuel gas is shown schematically in Figure Q-1. This flowsheet is not representative of the two-stage combustion process. Initially, the coal is prepared to remove refuse and pretreated to prevent caking. It is then sent to the gasifier where hydrogen, oxygen, or an external heat source are added to bring about the gasification reactions. The mixture leaving the gasifier requires further treatment to convert it into either low Btu fuel gas suitable for use by utilities or SNG. Steps in the treatment are essentially the same regardless of the gasification method, although design details, heat recovery, sulfur removal, etc. may be different. The gas mixtures pass through cyclone separators to remove fine particles and dust. It is then scrubbed to remove condensible materials and sent through a shift converter (if needed) to obtain the proper ratio of hydrogen to carbon monoxide for methane formation. The stream is then scrubbed with activated potassium carbonate, Rectisal, Purisol, or other proprietary solvent to remove carbon dioxide and hydrogen sulfide and, perhaps, is passed over activated carbon to remove organic compounds. At this point the Btu content of the gas is about 100-500 Btu/ft^3 STP and the option is available to use this material directly in generating electricity or further processing into a high Btu (1000 Btu/ft^3 STP) gas. In the latter case, iron oxide or equivalent absorbents remove any remaining traces of sulfur. The gas is methanated to increase its heating value and reduce the CO content to an acceptable limit. The methanated gas is dried and, if necessary, compressed to pipeline pressure.

There are many variations of the above scheme, some of the more common of which are:

(1) Oxygen or Air Addition Methods

   a. Lurgi process
   b. Koppers - Totzek process
   c. Bi-Gas (Bituminous Coal Research, Inc.)
   d. Synthane (Bureau of Mines)
   e. Molten-Salt Gasification (M. W. Kellogg Co.)
   f. Two-Stage Coal Combustion Process (Applied Technology Corporation)

(2) Hydrogen-Addition Methods

   a. Hygas (Institute of Gas Technology)
   b. Electrofluidic Coal Process (Iowa State University)

(3) Heat-Carrier Methods

   a. CO_2 Acceptor Process (Consolidation Coal Company)

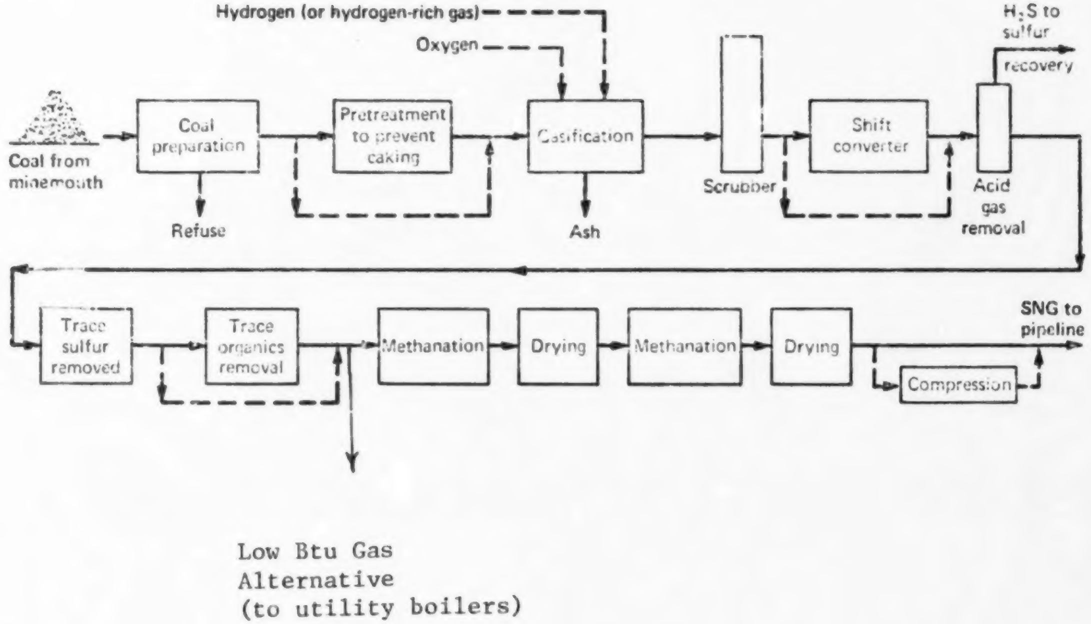
Hydrogen (or hydrogen-rich gas)
Oxygen
H_2S to sulfur recovery
Coal from minemouth
Coal preparation
Refuse
Pretreatment to prevent caking
Gasification
Ash
Scrubber
Shift converter
Acid gas removal
Trace sulfur removed
Trace organics removal
Methanation
Drying
Methanation
Drying
Compression
SNG to pipeline
Low Btu Gas
Alternative
(to utility boilers)

FIGURE Q-1. SCHEMATIC FLOW DIAGRAM FOR PRODUCING HIGH BTU FUEL BASES(a)

(a) Process streams are indicated by solid lines and alternatives by broken lines. Source: Reference (1).

For use in this analysis, four processes were considered: two that produced a low Btu gas corresponding to the option in which the fuel gas is combusted directly in a boiler to produce electrical energy (i.e., the gasification facility is closely coupled to the power plant); and two processes that produced high Btu gas corresponding to the option of transporting high Btu gas from a centralized gasification facility to several power plants and for use in space heating and industrial applications. Detailed process descriptions are given by Robson et al.,(Q-2) and Process Research Incorporated(Q-3), and will not be repeated here. The processes selected for this study are:

(1) Low Btu gas

- a. Lurgi process
- b. Two-stage Coal Combustion Process (molten iron combustion)

(2) High Btu gas

- a. Hygas process
- b. CO_2 Acceptor process.

The Lurgi Process is considered a "first-generation" system, i.e., a system based upon presently available, but not necessarily commercially utilized technology. All others are either "second- or third-generation" systems and are based on technology to be developed within the next 10 to 20 years. Also by making the above selection of processes, a hydrogen addition method was represented (Hygas) as well as a heat carrier method (CO_2 Acceptor). The two-stage coal combustion process appears to be the least developed of the four processes considered.

Low Btu Fuel Gas

Lurgi Process. Coal is introduced into the top of the gasifier through a coal lock, and distributed over a bed of coal that rests on a rotating grate. Oxygen and steam are introduced at the base of the bed, and flow countercurrently to the descending bed of coal. The gasification reactions occur in zones through the bed of coal in the gasifier. Initially coal reacts with air to form CO_2 according to Equation Q-2 while simultaneously coal reacts with steam to produce CO and H_2 according to Equation Q-1. The latter reaction is endothermic, hence, the bed temperature is kept below the fusion temperature of the ash. As the combustion gases proceed upward through the bed additional endothermic gasification reactions occur together with the water-gas shift reaction, Equation Q-4. Methane is produced by the reaction of coal with the hydrogen from the shift reaction and additional methane and higher hydrocarbons are produced by the devolatilization of the coal, Equation Q-5. Gasified materials leave from the top of the gasifier at 950 F, while ash is withdrawn from the base of the water-jacketed generator through an ash lock. Operating pressure may be close to 500 psi.

The gas mixture produced contains 3 to 15 percent methane (typically 10 percent). It is scrubbed to remove organic material, and then processed as described previously in Figure Q-1 to produce low Btu fuel gas.

Feed to the gasifier must be lumps of coal, 1/8 to 1-1/4 inch. Smaller pieces and dust particles are briquetted and then used. Noncaking coal is preferred. Subbituminous coals in the Western states seem to be better suited for the Lurgi process. The amount of oxygen required varies with the reactivity of coal, but typically might be equal to 30 percent of the weight of the charged coal.

Two-Stage Coal Combustion Process. The Two-Stage Coal Combustion process (Applied Technology Corporation) produces boiler fuel gas having a heating value of approximately 300 Btu per standard cubic foot. This gas is produced by the combustion of coal in a bath of molten iron in the presence of a substoichometric amount of air at essentially atmospheric pressure. The gas, rich in carbon monoxide and essentially sulfur-free, is then fed at a temperature of 2700 F directly to the burners of a boiler. Sulfur from the coal is removed via a slag layer and slag-iron separator and converted into elemental sulfur through a slag desulfurizer, condenser, and Claus unit.

High Btu Fuel Gas

Hygas Process (Institute of Gas Technology). The basic process features production of hydrogen from char by the use of electric energy. Coal is crushed and dried and for caking coals, the surface is oxidized by pretreatment with air at 800 F. It is then slurried with a light oil, pressurized to 1100 psi, and pumped to the top of the hydrogasifier. The hydrogasifier contains three sections. In the upper section the slurry is dried. Oil is driven off with the raw gas (containing about 17 to 25 percent methane) and is recovered and recycled. In the second section, coal is heated to 1200 to 1400 F and devolatilized. In the third section, the coal is heated to 1700 to 1800 F in the presence of a hot hydrogen-rich stream and steam, and is gasified.(Q-4)

About half of the carbon entering the reactor is gasified. The remaining char is conveyed to an electrothermal gasifier. There, electric energy is used to heat the bed. Steam is introduced, forming hydrogen and carbon oxides. The gas mixture, at about 1900 F and 1100 psi, is sent to the hydrogasifier. The remaining char is conveyed to a power plant where it is burned to generate steam and elctrical energy needed by the process. A 75-ton/day pilot-plant unit, including an electrothermal gasifier, is scheduled to begin operation this year.

CO_2 Acceptor Process (Consolidation Coal Company). Heat is supplied to the reacting coal by circulating bed of heated dolomite (MgO·CaO). The latter is reheated in a separate vessel by burning char with air. The process required neither oxygen nor hydrogen. However, the maximum temperature that can be used in the gasifier is limited to about 1600 F to avoid melting the circulating calcine. Operating pressures range from 150 to 300 psi. Under these conditions, the reaction rate of steam with bituminous coals is very low and the only satisfactory raw materials are lignites and some subbituminous coals. However, it is expected that further developments will permit the process to be adapted to higher grades of coal.

The lignite is ground, dried, and introduced into a fluidized-bed devolatilizer. Here it is reacted with a stream of gases rising from the gasifier, and with a portion of the calcined dolomite. The dolomite reacts with carbon dioxide, forming calcium carbonate. This reaction is exothermic, liberating heat for the carbon-steam reaction. The dolomite also absorbs sulfur compounds. Spent dolomite is returned to the generator and char is conveyed to the gasifier.

Additional amounts of calcined dolomite, and steam, are introduced into the fluidized-bed gasifier. Carbon reacts with steam, forming hydrogen and carbon monoxide. Removal of carbon dioxide promotes the water-gas shift reaction. Gases leave the top of the gasifier and enter the devolatilizer. Spent dolomite and unreacted char are conveyed to a fluidized-bed regenerator. Unreacted char is burned with air at about 1950 F, calcining the dolomite to restart the cycle.

Gas leaving the devolatilizer may contain about 20 percent CH_4 (dry basis). The procedure for converting this gas to high Btu gas has been described previously. However, in this process, the ratio of carbon to hydrogen may be such that the shift conversion step can be omitted. Bench-scale tests have been completed, and operations have started in a 30-ton/day gasification pilot-plant.

Emissions

Coal gasification, whether to produce a high or low Btu gas, results in a wide variety of process emissions. The exact nature of these waste streams will depend on the basis unit operation of the process. For each of the four processes considered in this program, material balances were made and emissions factors estimated. The environmental emissions are summarized in the module data sheets in Appendix A of this report. The qualitative types of emissions to be expected from coal gasification processes are shown in Table Q-1.

Air

In the production of both high and low Btu gas, air emissions include sulfur, mainly as SO_2, emanating from Claus plant tail gases. Since the production of low Btu gas involves the direct combustion in a boiler at the same site, power plant flue gas is also emitted. In most gasification processes (both low and high Btu product gas), CO_2

TABLE Q-1, ENVIRONMENTAL EMISSIONS ARISING FROM COAL GASIFICATION PROCESSES

Process Module	Emissions			
	Air	Water	Solid Waste	Other (By-Products)
Lurgi process & conventional boiler	1. Claus plant tail gas 2. Power plant flue gas	Minimal	Slag	Elemental sulfur
Two-stage coal combustion & conventional boiler	1. Power plant flue gas 2. Carbon dioxide 3. Claus plant tail gas	Waste waters	Slag	Iron Elemental sulfur
HYGAS	1. Claus plant tail gas 2. CO_2	Waste waters	1. Ash 2. Gypsum sludge[(a)]	Elemental sulfur
CO_2 acceptor process	1. Gaseous sulfur compounds (SO_2, H_2S and S) a. Claus plant tail gas b. Lignite drying step 2. CO_2	Waste waters	Mixed solids[(b)]	Elemental sulfur

(a) Arises from removal of SO_2 and Claus tail gas treatment.

(b) Ash plus unburned char plus spent acceptor solids.

is also emitted. In general, the higher the Btu content the greater the amount of CO_2 emitted.

Water

Coal gasification processes are liberal users of water, both as a raw material in the process for its hydrogen content and also as a process fluid. The higher the Btu quality of the gas, the larger the water requirements per unit of product. In most coal gasification processes, waste waters are also generated and must be treated.

Solid Waste

Coal gasification processes give rise to large quantities of solid wastes. They arise mainly due to the ash content of the coal, but also from processing to achieve sulfur removal. Typical solid waste streams (see Table Q-1) include slags (both Lurgi and Two-Stage Combustion Processes), ash (Hygas process), gypsum sludges (Hygas process), and mixed solids (CO_2 Acceptor process). In addition all produce elemental sulfur which, if it cannot be sold to the chemical industry, may be considered a solid waste.

Land Use

It is estimated that a 234 x 10^9 Btu/day (output) gasification plant, i.e., a plant large enough to supply gas to a 1000 MW power station would require between 175 and 200 acres; about 175 acres in the case of low Btu gas and 200 acres in the case of high Btu gas. Since in the case of low Btu gasification, the power plant would be located in close proximity, it is estimated that another 1000 acres would be required for a total of 1175 acres for the gasification plus boiler complex.

Other

It is possible that by-products could be recovered and sold. The main by-product from most gasification processes is elemental sulfur. If sulfur cannot be sold, then it would have to be disposed of as a dry landfill. Other by-products are also produced which are specific to the gasification process in question. For example in the Two-Stage Combustion process, iron is recovered from the sulfur removal step as an iron rich solid (up to 1 percent FeS). It is expected that this material could be sold for use in the steel industry.

Pollution Control

Methods

Coal gasification is a pollution control method and represents an alternative to flue gas cleaning, solvent refining, chemical cleaning, coal washing, fuel switching, etc. to meet emission regulations.

In most processes, aqueous waste waters are treated using conventional technology, i.e., biological oxidation, gravity separation, and a wide variety of physical chemical unit operations (ion exchange, reverse osmosis, adsorption, filtration, chlorination, etc.). No one technique or method is universally employed.

The ash in the coal is usually removed in front-end processing equipment. For example, in the Lurgi process it is removed off the bottom of the gasifier, while in the CO_2-Acceptor process it is removed along with unburned char and spent acceptor (reacted dolomite) from the acceptor-stripper unit just downstream from the gasifier.

Sulfur is removed from the coal in coal gasification processes using a wide variety of technology. Most often it is volatilized under reducing conditions to form H_2S, scrubbed from the fuel gas, stripped from the absorption liquor as a concentrated H_2S stream, and converted to sulfur using Claus plant technology. If necessary, a Claus plant tail gas treatment process is also provided. The volatilization process usually occurs in the gasifier per se with the sulfur appearing in the off-gas principally as H_2S along with small quantities of COS and CS_2. The fuel gas scrubbing and stripping steps to remove and concentrate these sulfur compounds (mainly H_2S) is accomplished by any one of a vast array of processes: (1) amine scrubbing systems, (2) hot potassium carbonate process, (3) sulfinal process (Shell Oil Company), (4) seaboard and vacuum carbonate processes (Koppers Company), (5) the phosphate process (Shell Development Company), (6) wet iron box process, (7) the Thylox process, (8) hot-ferric oxide process, and (9) dolomite acceptor process to name a few. The concentrated H_2S stream is usually then sent to a Claus plant.

In the Claus process, H_2S is combusted under precisely controlled condition so that one-third of it is converted to SO_2. The cooled combustion products are catalytically reacted to form elemental sulfur according to the following equation.

$$2H_2S + SO_2 \overset{cat}{\rightleftarrows} 3S + 2H_2O$$

after which the sulfur is condensed and separated. However, recovery is not complete even with three converters, and as much as 5 percent of the entering sulfur is contained in the exit (tail) gas. Recently developed tail gas treating technology, e.g., the Beavon, Cleanair, and IFP processes, achieves recovery of almost all of the remainder. Consequently sulfur removal of 99.5 to 99.9 percent is achieved on the incoming H_2S.

Effectiveness and Cost

The cost to utilities of achieving pollution control through the substitution of clean fuel gas (either low or high Btu gas) will depend on the price at which the fuel gas is available locally relative to that of other fuels. Process Research Incorporated(Q-3) estimated coal gasification costs (process conversion costs) in ¢/10^6 Btu for the Two-Stage Combustion, CO$_2^-$ Acceptor, and Hygas processes. These process conversion costs do not include the price of coal or in the case of high Btu gas, transportation costs. Economic evaluations were based on the following standard American Gas Association accounting procedures which were adopted by the Office of Coal Research as standard:

20-year plant life
Straight line depreciation
9 percent gross return on rate base
Financing - 65 percent debt - 35 percent equity
Interest rate - 7.5 percent
Federal income tax - 48 percent.

Also, Robson et al.(Q-2) estimated the performance and economics of a plant producing fuel gas for a 1000 MW low pressure plant with a 70 percent operating factor. The major capital cash areas were gasification - 45 percent, air compression - 20 percent, coal handling and preparation (mainly briquetting) 11 percent, and general facilities - 9 percent. Additional items make up approximately 15 percent of the capital costs. The results of both studies are summarized in Table **Q**-2.

As seen in Table Q-2, plant costs for the low Btu gas processes range from about 20 to 46 million dollars or between \$20 to \$48 per kw if the gasification plant is owned by the utility. Pollution control costs range from under 1¢ to about 29¢/10^6 Btu (output). The lower value for the conversion costs ($\sim$1¢/10^6 Btu) is for the two-stage combustion process and takes into account by-product credits for slag, iron, and sulfur. It should be pointed out that, to date, only prototype combustor studies and laboratory bench-scale studies have been performed. Due to the small size of the experimental equipment, and lack of pilot-scale studies, these low estimates are viewed with considerable skepticism.

The cost of coal is not included in the above estimates because it varies from one plant location to another. The total product selling price at the plant can be developed by adding to the above prices the cost of coal in cents per million Btu multiplied by a factor 1.01E where (E) is the efficiency of the gasification process.

For high Btu gas, plant costs range from \$124.9 to 209 million for a 250 x 10^9 scfd plant (1,000 MW) or between \$117 and 197/kw. Conversion costs range from 35 to 50¢/10^6 Btu. Again the cost of coal was not included. These estimates would appear to be quite optimistic. Bresler and Ireland(Q-1) provide "ballpark" cost estimates between about \$0.60

TABLE Q-2. ESTIMATED COAL GASIFICATION PROCESS ECONOMICS

Process	Reference	Product Gas	Generation	Plant Site		Plant Cost		Conversion Cost(a) ¢/MM Btu	
				MW	10^9 Btu/day	MM $	$/kW	20 yr. Depre.	5 yr. Depre.
Lurgi	G2	Low Btu	1st	965	228	46.3	48	28.6(b)	--
Two-Stage Combustion	G3	Low Btu	3rd	1000	234	20.3	20.3	0.44	3.7
CO_2-Acceptor	G3	High Btu	2nd	1060	250	124.5	117	35.5	58.5
HYGAS	G3	High Btu	2nd	1060	250	209	197	50	87

(a) Does not include cost of fuel.

(b) Depreciation period not known.

to \$1.00 per million Btu (not including the cost of coal). Also Battelle has recently been engaged in a detailed design study of a coal gasification plant to be located in the western United States. Conversion costs in this study averaged about $\$1.00/10^6$ Btu. In any case, it would appear doubtful whether high Btu gas, as envisioned by processes currently being developed, will be used for power plant fuel. It will, in all probability, find its place as a supplier of SNG for home space heating and industrial application.

References

Q-1. Bresler, S. A., and Ireland, J. D., "Substitute Natural Gas: Processes, Equipment, Costs", Chemical Eng., pp. 94-108 (October 16, 1972).

Q-2. Robson, F. L., et al., "Technological and Economic Feasibility of Advanced Power Cycles and Methods of Producing Nonpolluting Fuels for Utility Power Stations", Report No. PB-198-392 (December, 1970).

Q-3. Process Research Incorporated, "Evaluation of Fuel Treatment and Conversion Processes", report prepared for Environmental Protection Agency, Office of Air Programs, Contracts No. 68-02-0242 and CPA 70-1 (July 7, 1972).

Q-4. Annual Report, Office of Coal Research, 1972.

APPENDIX R

GENERATION OF ELECTRICITY

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APPENDIX R

GENERATION OF ELECTRICITY

Environmental Emissions in the Generation of Electricity

Energy Sources for Generating Electricity

Presently, generation of electricty in the United States amounts roughly to 35 x 10^9 kwhr weekly, with the probable total generation for 1972 expected to be about 1.7 x 10^{12} kwhr. Approximately one-fifth of this will come from hydropower, with the remainder from fossil-fuel-fired generating plants. Of these, steam-generating units predominate, with a rapidly increasing use of gas turbines at percentage levels well beyond their earlier application as peak-shaving units.

Table R-1 shows that coal has been and will continue to be a major source of energy for conversion into electricity, based on a generating capability in 1970 of 340,000 MW, in 1980 of 665,000 MW, and in 1990 of 1,260 MW, representing essentially a doubling time of ten years. The estimate for coal usage in 1990 is probably quite conservative in that the figures which were forecast for nuclear energy seem highly optimistic in light of developments which have occurred since the estimate was made.

TABLE R-1. ENERGY SOURCES USED BY ELECTRIC UTILITIES(a)
(Equivalent tons of coal based on 25 x 10^6 Btu/ton)

Source	1970		1980		1990	
	Tons	Percent	Tons	Percent	Tons	Percent
Coal	300.2	55.0	472.0	41.9	613.6	28.7
Gas	150.1	27.6	162.3	14.9	200.2	9.4
Oil	79.3	14.6	136.4	12.1	145.1	6.8
Nuclear	15.2	2.8	365.5	21.6	1,176.1	55.1
Total	544.8	100.0	1,127.2	100.0	2,135.0	100.0

(a) Federal Power Commission

Since 1970, at least along the East Coast, low-sulfur residual fuel oil has largely displaced coal for central-station power plants, simply because low-sulfur fuel oil has been made available as needed. One large midwest utility has been shipping large quantities of low-sulfur coal from the western states. But, at least, for the time being, the extraordinarily large reserves of coal in North Dakota, Montana, Wyoming, Colorado, and Utah with less than one percent sulfur are considered unavilable to the major utilities east of the Mississippi River.

Although, as shown in Table R-1, the percentage of electricity generated from coal is expected by the Federal Power Commission to decrease markedly over the next two decades, the tonnage requirements will increase about 60 percent between 1970 and 1980, and another 30 percent between 1980 and 1990. If obtained from eastern coal fields, this coal will contain what is now considered to be excessive amounts of sulfur; on a weighted basis, judged from past experience, the average sulfur content over the next few years can be assumed to be 2.2 percent.

With natural gas, the present critical supply situation casts considerable doubt on any expanded use of natural gas for generating electricity, either in conventional steam plants or in gas turbines or combined-cycle plants. Hence, the estimates of increased use of natural gas shown in Table R-1 are probably unrealistic. Unless some radical change occurs to increase the availability of natural gas, not foreseen now, it can be assumed that this sulfur-free source of energy will not play a significant role in the generation of electricity beyond the next few years. Imported liquified natural gas, synthetic natural gas from coal, and pipeline gas from the North Slope of Alaska will be priced at $1 per million Btu or more, making them unattractive as energy for electricity generation. Fuel now contributes about half the cost of electricity at the station's bus bars, so that increasing prices for fuel will have a large effect on the price of electricity.

Nuclear generation is important here only because it may partly replace the use of fossil-fuels, and hence, decrease the environmental emission of conventional power plants. As stated earlier, the tremendous growth of the nuclear industry shown in Table R-1 is probably highly optimistic. Delays in the construction of nuclear power plants, technical problems such as emergency core cooling, and public concern about siting of nuclear stations are all contributing to unexpected delays in availability. Therefore the future use of fossil-fuels, mainly coal and fuel oil, certainly will be no less than is shown in Table R-1.

Energywise, then, coal will continue to supply the greater part of our electricity until 1990. Some plants will probably burn low sulfur coal and other coal-burning plants will employ stack gas cleaning. Natural gas will be limited for generating electricity, probably being reserved for residential heating and industrial and commercial uses for which gas is uniquely suited. Fuel oil, with a sulfur content as low as 0.5 percent, will be used widely on the Eastern Seaborad within the limits set by import quotas and the construction of desulfurizing plants.

Conventional Power Plants

As operated today, central-station power plants have no control over SO_2 emission other than by selection of fuels. Likewise, NO_x is uncontrolled. Particulate matter alone can be removed from stack gases by well-developed techniques with collection efficiencies up to 99 percent, but the electrostatic precipitators required for such good performance fail with low-sulfur coal because the electrical resistivity of the fly ash then becomes excessively high. Under such conditions, collection efficiency may be no higher than 50 percent. Improved collectors will be needed to meet regulations which are now being promulgated.

Sulfur Dioxide. Essentially, all the sulfur in fuels leaves the stack as sulfur oxides. In the case of some coals containing appreciable amounts of limestone or dolomite as mineral matter, as much as 5 percent of the sulfur may be captured by the ash but, generally, insignificant amounts of sulfur are retained in the furnace. Sulfur dioxide is the usual form, with about 1 percent of the total sulfur in the fuel being emitted as SO_3.

Table R-2 shows the amount of SO_2 emitted per day from a 1000-MW unit operating under base-load conditions with fuels of different sulfur content. Timewise, bituminous coal with 2.2 percent sulfur represents practice today; bituminous coal in some plants and lignite in others with an average sulfur content of 1.5 percent may occur in 1980; and complete conversion to lignite with a sulfur content of 0.8 percent or less might be delayed until 1990. Fuel oil containing only 0.5 percent sulfur is available in limited quantities today. It is not likely that much oil with a lower sulfur content will be available in the future, though some which is 0.3 percent or less is now being burned on the East coast.

TABLE R-2. EMISSION OF SULFUR DIOXIDE FROM CONVENTIONAL FUEL-FIRED POWER PLANTS

Fuel	Sulfur, percent	Heating Value, Btu/lb	Emission of SO_2, tons/1000 MW day(a)
Bituminous coal	2.2	13000	171
Sub-Bituminous coal and lignite	1.5	10000	153
Lignite	0.8	7000	117
Fuel oil	0.5	19500	26

(a) Based on 8500 Btu/kwhr for all fuels.

The most striking point here is that the lower sulfur content of lignite compared with bituminous coal does indeed decrease the emission of SO_2, but the lesser heating value of lignite removes much of the apparent advantage. Under the conditions assumed here, substituting lignite for bituminous coal would reduce SO_2 emission only about one-third. The great advantage of low-sulfur fuel oil also is strongly evident.

It is apparent that the emissions are reduced somewhat by the choice of solid fuels, but that, short of replacing all forms of coal with low-sulfur fuel oil--a most unlikely alternative in light of Table R-1--no very large benefits can be expected. The only other paths open are to desulfurize flue gases, to devise wholly new methods to remove sulfur from coal, to convert coals into sulfur-free liquid or gaseous fuels, or to develop other systems for converting the chemical energy in fuels into electricity.

Nitrogen Oxides. Nitrogen oxide in flue gas originates from two sources, the dissociation of the nitrogen compounds in the fuel and the reaction of atmospheric nitrogen with oxygen atoms during combustion. Few data are available as yet on the role played by fuel nitrogen, but there is general agreement that it cannot be ignored. Combustion-formed NO is more important. The major factor involved is temperature, the amount of NO formed increasing rapidly as the temperature rises above about 2400 F. At temperatures above 3000 F, this fixation reaction proceeds much more rapidly. A further point is that the rate of dissociation of NO back into N_2 and O_2 is much slower than the rate of formation of NO, so that peak temperature reached is much more important than the cooling rate in establishing the NO content in stack gas.

Table R-3 summarizes some recently available data on the emission of NO from large boiler furnaces.

TABLE R-3. EMISSION OF NITROGEN OXIDES FROM LARGE BOILER FURNACES(a)

Fuel	Average Boiler Rating, MW	NO Emission, ppm			NO Emission, tons/ 1000 MW Day		
		Full Load	Intermediate Load	Low Load	Full Load	Intermediate Load	Low Load
Coal	495	990	740	700	95	51	36
Gas	290	590	420	280	31	20	8
Fuel oil	257	360	270	260	17	10	6

(a) Bartok, W., Crawford, A. R., and Piegari, G. J., "Systematic Field Study of NO_x Emission Control Methods for Utility Boilers": E.P.A. Contract CPA 70-90, December 31, 1971, Esso Research and Engineering Company.

The NO emission data as reported by Esso and calculated as NO are based on 3 percent O_2 in dry flue gas. For simplicity, the conversion here from parts per million to tons NO_2 per 1000 MW day assumes 550 ppm as being equivalent to 1 lb NO_2 per million Btu. Assuming further that the heat rate is 8500 Btu/kwhr for all three fuels at the three loads listed provides the calculated approximate NO_2 loadings in the last three columns of Table R-3. These simplifying assumptions permit judging the relative emissions of type of fuel and of load even though the assumptions are an approximation at best.

Table R-3 shows that the fluid fuels, gas and oil, produce less NO_2 than pulverized coal, probably because the combustion of gas or of droplets of fuel oil results in lower flame temperatures than the burning of solid particles of coal that go through a devolatilization step followed by oxidation of the resultant coke particles. In the boilers surveyed, fuel oil produced about half as much NO_2 as natural gas except at low loads where the two fuels were comparable. The reason for this is not clear.

Emission of NO_2 drops appreciably as the load in a boiler is less. Table R-3 shows that at low loads, with all three fuels, the amount of NO_2 formed is a half to a fourth as much as at full load for the same amount of electricity generated. The Esso study shows that the uncontrolled emission of NO_2 depends nearly linearly on the gross boiler load expressed as percentage of full load, regardless of the fuel.

Decreased emission of NO_2 is obtained mainly by lowering flame temperatures. Combustion modifications, such as using low excess air or staged combustion have been moderately successful with gas firing, in some cases decreasing NO_2 emission by 80 percent. However, burner design and spacing, heat transfer in the furnace, and probably other unidentified factors influence the effectiveness of combustion changes so that NO_2 control is still troublesome even with gas firing.

Although fuel oil leads to lower uncontrolled NO_2 levels than gas, combustion modifications are less effective. Again, the reasons are not entirely clear, although flame and furnace temperature undoubtedly are responsible.

Coal, with its more involved combustion process, poses problems with low excess air or with staged combustion in unburned carbon in the fly ash. Hence, the control of its already high NO_2 levels will be much more difficult with pulverized coal than with gas or fuel oil, although Esso reported few problems in the boilers it tested.

The impact of NO_2 emission in the future certainly will be lessened by the use of combustion modifications, but the exact extent is difficult to forecast now. With coal providing the energy for generating more than half the electricity used today, most emphasis must go into combustion modifications that will still permit reasonably low levels of carbon in fly ash.

Particulate Matter. Emission of particulate matter is a serious problem with pulverized coal-fired boiler furnaces, where a major part of the mineral matter in the coal is carried out of the furnace with the flue gas. Dry-bottom furnaces which presently make up the largest part of our steam-generating facilities usually retain less than a fifth of this mineral matter in the form of wall slag or bottom deposits; the remainder goes through the heat-recovery systems to be captured by mechanical collectors or electrostatic precipitators, or passes out of the stack. Slag-tap furnaces, not being made presently, capture as much as 90 percent of more of the mineral matter in the coal.

Oil-fired boiler furnaces emit small quantities of particulate matter because of the inorganic matter in residual fuel oil, but the quantity is generally less than 1 percent than from coal-fired furnaces. Although the quantity of particulate matter is low with oil firing, visible plumes are common because of the size range of the particles.

Gas-fired boiler furnaces emit no particulate matter unless combustion conditions are so bad that thermal cracking of the hydrocarbons produces carbon particles. This is an extreme condition essentially never occurring in large central-station power plants.

Mechanical collectors remove only particles larger than about 10 microns, but electrostatic precipitators now being designed have an over-all collection efficiency of 99 percent even with submicron particles. As noted earlier, this efficiency cannot be maintained when the fly ash has an electrical resistivity greater than 10^{10} ohm centimeters, but increasing the operating temperature to 600 F or higher appears likely to solve this problem.

Table R-4 lists the emission of particulate matter from coal-fired boiler furnaces of the three common firing systems assuming that 90 percent of the mineral matter is captured during combustion by the cyclone furnace, 50 percent by the slag-tap furnace, and 20 percent by the dry-bottom furnace.

TABLE R-4. EMISSION OF PARTICULATE MATTER FROM COAL-FIRED BOILER FURNACES (10-percent-ash coal; 8500 Btu/kWh)

	Emission from Stack, tons/1000 MW day	
Type of Firing	50 Percent Collection Efficiency	99 Percent Collection Efficiency
Cyclone	40	0.8
Slag Tap	200	3.9
Dry Bottom	310	6.2

Other Pollutants. Small amounts of carbon monoxide are emitted by large boiler furnaces, but the emission levels seldom exceed 100 ppm under proper operating conditions. With low excess air and with staged combustion to control NO_2 emission, CO may increase as the limits of satisfactory combustion are reached. An upper level higher than 1000 ppm is unlikely. The emission level at 100 ppm CO would be 9 tons per 1000 MW day. At 1000 ppm, emission would be 90 tons per 1000 MW day, based on 0.084 pound CO per million Btu input and a heat rate of 8500 Btu/kwhr.

Unburned hydrocarbons from oil- or gas-fired boiler furnaces are negligible. Similarly, polynuclear aromatic compounds resulting from combustion usually are insignificant because the high temperatures in the furnace, usually reaching at least 3000 F, dissociate any PNA that may be formed early in the combustion process. Benzp (α) pyrene, a typical compound, probably does not exceed 1 gram per million Btu input in coal-fired furnaces, equivalent to about 0.2 ton per 1000 MW day.

Thermal Effects. Large modern steam-generating power plants presently have reached a plateau in thermal efficiency, no appreciable gains having been reached over the past five years. This is due largely to operational problems limiting the steam temperature to 1000 F. By operating at 3500 psi, well above the critical pressure, and by using a sophisticated reheat cycle, the best of today's plants achieve a heat rate of about 8500 Btu/kwhr, equivalent to 40 percent overall thermal efficiency. The remaining 60 percent of the heating value of the fuel appears as sensible heat in the flue gas and in the condenser cooling water, with roughly 10 percent in the flue gas and 50 percent in the coolant.

On this basis, 2×10^{10} Btu appears in the flue gas and 1×10^{11} Btu appears in the condenser water for a 1000 MW day. The sensible heat in the flue gas is necessary to maintain the gas temperature at about 325 F, high enough to assure a buoyant plume from the top of the stack and to be above the dew point to minimize stack corrosion. The sensible heat in the condenser water is dissipated in rivers or other natural bodies of water, or as is becoming more common today, in natural-draft cooling towers. Roughly, in such towers, 1 x 10 Btu will evaporate 1 x 10 pounds of water or 12 million gallons of water per day for baseload operations of a 1000 MW unit, assuming no radiation or convective heat losses.

The magnitude of the total thermal effect on the environment can be compared with solar radiation, supplying approximately 350 Btu per hour per square foot. On this basis, assuming 8 hours of sunshine per day, 46 million square feet of surface will receive the same energy normal to the sun as must be dissipated from a 1000 MW plant over 24 hours. At 40 degrees North latitude and at the equinoxes, this becomes 70 million square feet of actual sunshine-receiving surface, or about 2.5 square miles. It is evident that, although a dissipation of 1.2 x 10 Btu in 24 hours is a large amount of energy, its impact is relatively minor compared with solar radiation.

Combined Cycle

There are many possible "combined cycles" being considered for updated power plants, including combinations of various combustors and heat recovery systems. Most consideration presently is being given to pressurized boiler furnaces combined with gas-turbine sets. In a typical system, the gas turbine provides the energy to compress combustion air for the furnace to, perhaps, 100 psi. The furnace, in which the fuel is burned, converts a part of the thermal energy to steam sent to a steam turbine, and then expands the hot gases in a gas turbine where additional electricity is generated. Alternatively, combustion may occur in the gas turbine, with a waste-heat boiler to extract thermal energy from the gas turbines exhaust. Other cycles are possible, including the injection of steam into the gas turbine to increase overall cycle efficiency. The principle advantage of combined cycles is an appreciably higher thermal efficiency than is possible with conventional systems. Whereas the usual system with steam at 1000 F and 3500 psi has an overall heat rate as low as 8500 Btu/kwhr or 40 percent, a combined cycle may achieve 6800 Btu/kwhr for an overall efficiency of 50 percent.

The impact of a combined cycle on the environment cannot be assessed until the cycle details are decided. The effect of pressurized combustion on emission of NO_2 is uncertain, but, based on data for gas turbines, NO_2 emission under most conditions of take-off in aircraft engines does not exceed about 5 pounds per 1000 pounds of fuel burned(R-1) equivalent to 25 tons of NO_2 per 1000 MW day. It is probable that this level would not be exceeded in a combined cycle, where the pressurized furnace essentially would be replacing the conventional gas-turbine combustion.

Of necessity, a combined cycle will require a conditioned fuel essentially free of ash and very low in sulfur. Dirty fuels will cause serious operational problems with the gas turbine, and although it is possible eventually that the pressurized boiler furnace preceding the gas-turbine expander might be fired with a "dirty" fuel, and remove ash and sulfur contaminants before the hot products of combustion pass to the gas turbine, such a system has not been devised as yet.

Unburned hydrocarbons and CO are present in small quantities in gas-turbine exhaust, but their impact will be small in a combined cycle. Assuming again that the pressurized boiler furnace simply replaces the conventional gas-turbine combustor "can", and based on cruise conditions in aircraft where the emission of HC is only 6 pounds per 100,000 pounds of fuel, the emission of HC from a combined cycle might be no more than 600 pounds per 1000 MW day. Carbon monoxide emission during cruise is about 1 pound per 1000 pounds of fuel, equivalent here to 5 tons of CO per 1000 MW day.

References

R-1. Combustion Planning Study, 1971, p VI-5.

APPENDIX S

STACK GAS CLEANING

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APPENDIX S

STACK GAS CLEANING

Summary

Well over 50 individual processes for removing SO_2 from stack gas have been identified. A number of processes have been applied successfully to control smaller industrial sources including oil fired boilers. Technology which has been developed through the joint efforts of industry and EPA over the past few years is now being reduced to sound engineering practice. Typical of the throwaway processes is wet limestone scrubbing and typical of the recovery processes are MgO scrubbing with H_2SO_4 production and alkali scrubbing (sodium or ammonium salts) with sulfur production. The removal efficiencies for SO_2, NO_x, and fly ash are assumed to be linear functions of time during the period 1975 to 1990 with a range of 75 to 90 percent for SO_2, 0 to 20 percent for NO_x, and 99 to 99.5 percent for fly ash. Air, water, and solid waste emissions for the typical processes have been estimated by means of material balances and a knowledge of the process flowsheets with the aid of judicious assumptions when necessary. Emissions were estimated for a typical eastern coal, a typical western coal, and a typical fuel oil for 1975 and 1990. Stack gas cleaning processes for power plant application are estimated to cost an average of 2.4 mills/kwhr (24.6 cents/10^6 Btu, for heat to electricity efficiency of 35 percent) with a range of 1.1 to 7.7 mills/kwhr (11.3 to 79.0 cents/10^6 Btu) depending upon the specific case under consideration. Stack gas cleaning will provide the only means for reducing emission from the 30 to 50 percent of the existing coal and oil fired plants where low sulfur fuels will not be available. This discussion is predicated on many assumptions and, therefore, must be considered as a "rough cut" at the problem rather than a definitive analysis.

Technology

The various technologies being developed for SO_2 removal from stack gas are summarized in Figure S-1. This figure was developed from information presented by Slack.(S-1) One of the major divisions in the technologies is between recovery of the SO_2 in useful form and formation of a product intended for discard as a solid waste; both the recovery and throwaway methods can be carried out in either wet or dry systems. The throwaway methods convert an air pollution problem to a solid waste while the recovery methods would require an electric utility or some selected agent to market a chemical product.

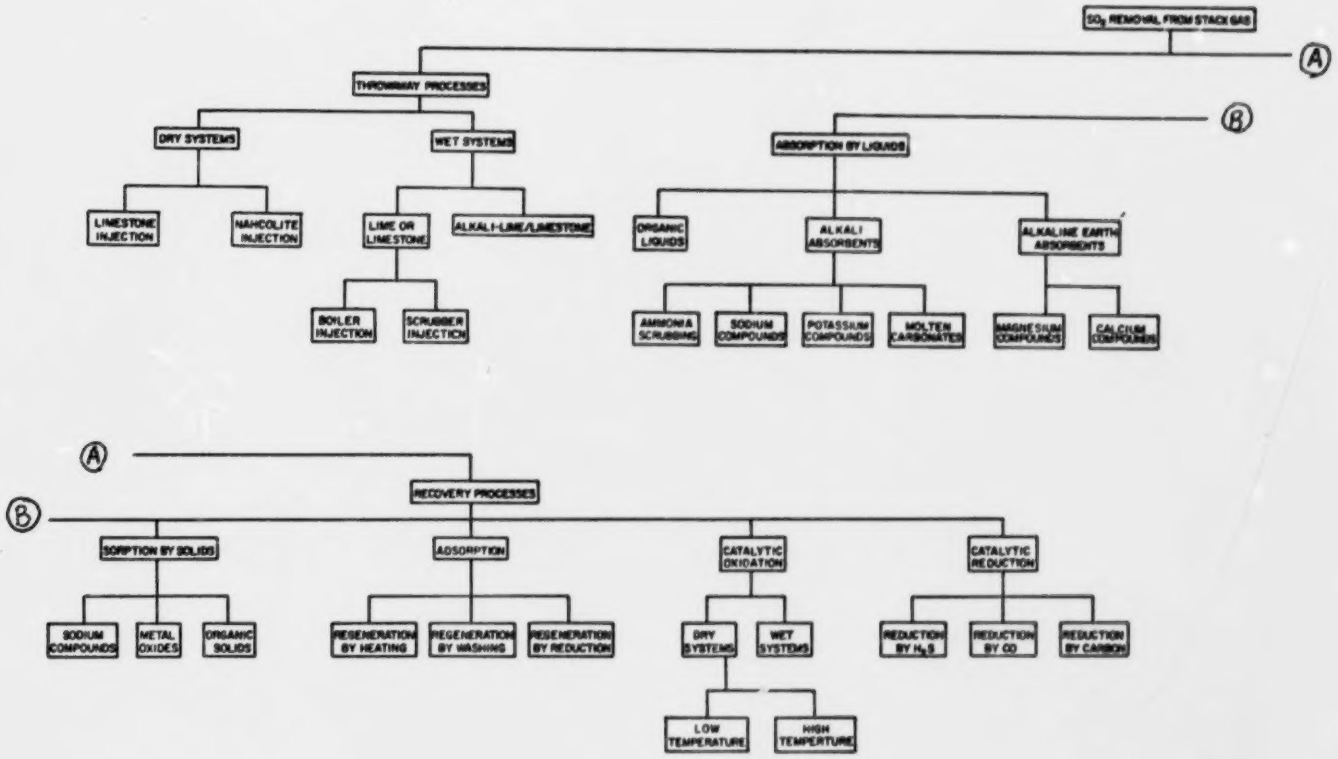
SO$_2$ REMOVAL FROM STACK GAS
Ⓐ
THROWAWAY PROCESSES
DRY SYSTEMS
WET SYSTEMS
LIMESTONE INJECTION
NAHCOLITE INJECTION
LIME OR LIMESTONE
ALKALI-LIME/LIMESTONE
BOYLER INJECTION
SCRUBBER INJECTION
Ⓑ
ABSORPTION BY LIQUIDS
ORGANIC LIQUIDS
ALKALI ABSORBENTS
ALKALINE EARTH ABSORBENTS
AMMONIA SCRUBBING
SODIUM COMPOUNDS
POTASSIUM COMPOUNDS
MOLTEN CARBONATES
MAGNESIUM COMPOUNDS
CALCIUM COMPOUNDS
Ⓐ
Ⓑ
RECOVERY PROCESSES
SORPTION BY SOLIDS
ADSORPTION
CATALYTIC OXIDATION
CATALYTIC REDUCTION
SODIUM COMPOUNDS
METAL OXIDES
ORGANIC SOLIDS
REGENERATION BY HEATING
REGENERATION BY WASHING
REGENERATION BY REDUCTION
DRY SYSTEMS
WET SYSTEMS
LOW TEMPERATURE
HIGH TEMPERTURE
REDUCTION BY H$_2$S
REDUCTION BY CO
REDUCTION BY CARBON

FIGURE S-1. TECHNOLOGIES FOR THE REMOVAL OF SO$_2$ FROM STACK GAS

The various technologies for SO_2 removal outlined in Figure S-1 can be subdivided into more than 50 in individual processes. However, processes which are most likely to be commercially applied in the near future must meet the following criteria:

1. Technical feasibility
2. Advanced state of development
3. Utility company acceptance
4. Marketable end product (recovery processes)
5. Possibility of solving process problems.

The list of well-developed processes that have gained some degree of utility company acceptance in the United States is as follows:

1. Wet lime/limestone scrubbing
2. Double alkali scrubbing
3. Wellman-Lord process
4. Stone & Webster/Ionics process
5. MgO scrubbing
6. Monsanto Cat-Ox process.

All of the processes have evolved from joint efforts by government and industry. EPA has provided some support for all of the process, mainly in the demonstration stage. The EPA has given financial assistance to full-scale demonstration plants of the Wellman-Lord process at Northern Indiana Public Service Company's Mitchell station, the Stone & Webster/Ionics process at a Wisconsin Electric Power Company station in Milwaukee, the Chemico-Basic MgO scrubbing process at Boston Edison's Mystic station, the Monsanto Cat-Ox process at Illinois Power's Wood River station, and wet limestone scrubbing for the City of Key West. The latter three plants are currently in operation. In addition, the EPA is funding an extensive pilot-plant study of a wet/limestone scrub unit at TVA's Shawnee station where it had funded an earlier study on dry limestone injection. It has recently been announced that the EPA is going to fund a pilot-plant study of the double alkali process at Nevada Power Company's pilot plant.

Ammonia scrubbing should be added to the list because of its interchangeability with sodium compounds in wet scrubbing and because of favorable scrubbing experience in other countries. Ammonia scrubbing is similar to the Wellman-Lord process except that the cation in the scrubbing liquor is NH_4^+ rather than Na^+. In order to narrow the scope of this study to manageable proportions, the list of seven stack gas cleaning processes has been divided into three categories and one typical process has been chosen to represent each category for further analysis. These categories and processes are as follows:

1. Throwaway-wet limestone scrubbing
2. Recovery of H_2SO_4 - MgO scrubbing
3. Recovery of sulfur-ammonia scrubbing.

The throwaway processes are likely to be applied before the recovery processes because of the reluctance of the utility industry to enter the chemical business. The most advanced throwaway process, wet limestone scrubbing, has an SO_2 removal efficiency of about 75 percent(S-2), while the most advanced recovery process, MgO scrubbing, has an SO_2 removal efficiency of about 90 percent(S-3). Therefore, it seems reasonable to assume an efficiency of 75 percent for SO_2 removal in 1975 and 90 percent in 1990 with a linear increase in removal efficiency with time. None of the well-developed stack gas cleaning processes have given any indication of removing NO_x from stack gas; however, it is conceivable that some NO_x removal in 1975 and 20 percent in 1990 with a linear increase in removal efficiency with time. However, it must be recognized that more significant reductions in NO_x emissions will probably be attained through combustion modifications. The proposed state regulations on fly ash removal coupled with existing technology dictate an efficiency of 99.0 percent for fly ash removal in 1975 and 99.5 percent in 1990 with a linear increase in removal efficiency with time.

Environmental Emissions

Process Flowsheets

The best method for assessing the environmental emissions of stack gas cleaning processes is to determine the emissions by means of a material balance. Typical flowsheets for the three processes under consideration were adapted from the work of the M. W. Kellog Company(S-7), from the TVA report on wet limestone scrubbing(S-7), and from a recent EPA report(S-8), and are shown in Figures S-2, S-3, and S-4. In addition to the flowsheets--a knowledge of the process chemistry is needed to perform a material balance.

Process Chemistry for Wet Limestone Scrubbing

Very little in the way of chemical and kinetic data has been reported on the limestone-wet scrubbing system. However, work in the area has recently been accelerated under EPA contracts. Data are available in the literature on the system CaO-SO_2-H_2O but these are not considered applicable because of the absence of carbon dioxide. One of the major questions is the nature of the calcium compound that actually reacts

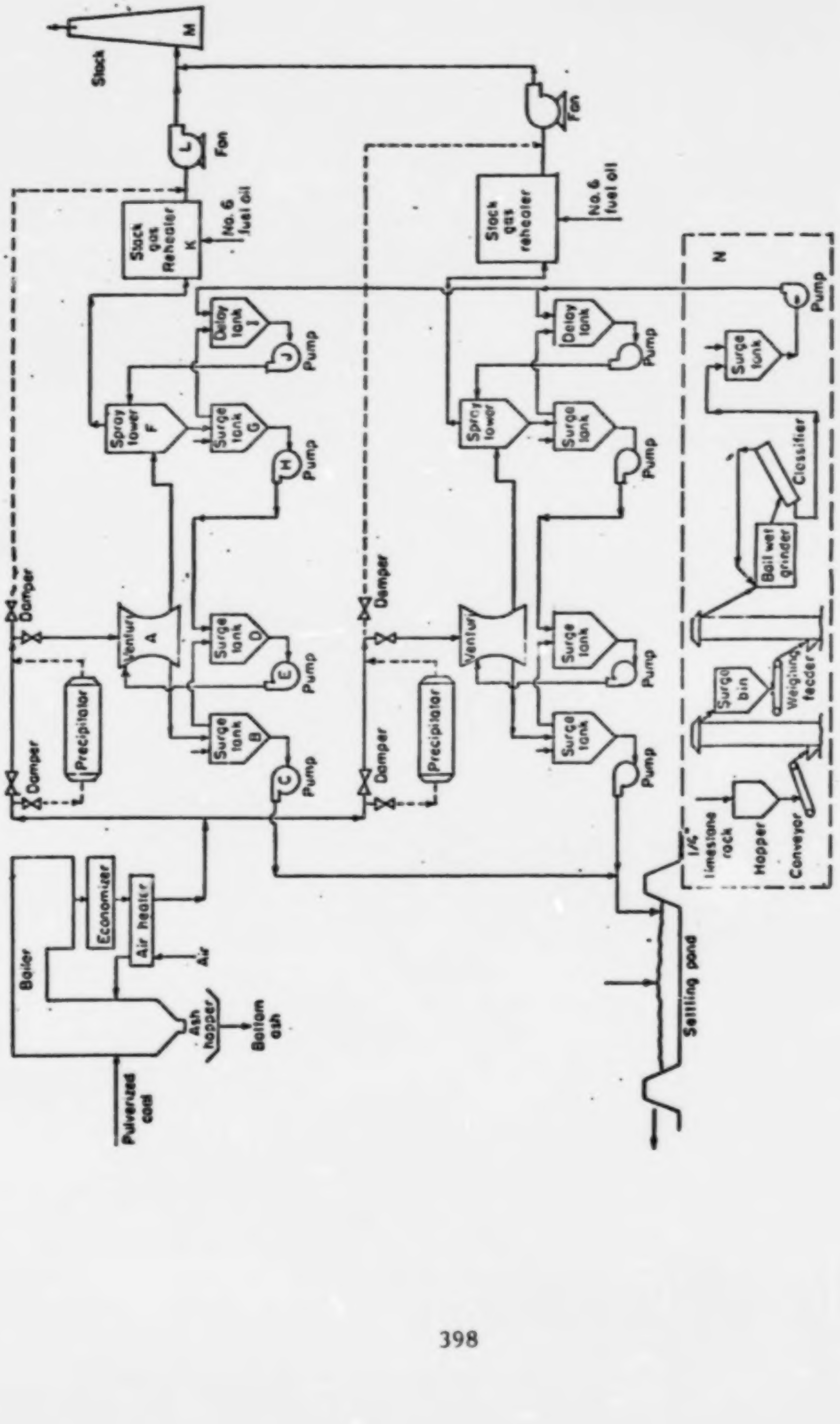
Pulverized coal
Boiler
Ash hopper
Bottom ash
Economizer
Air heater
Air
Damper
Precipitator
Venturi A
Surge tank B
Pump C
Surge tank D
Pump E
Spray tower F
Surge tank G
Pump H
Delay tank I
Pump J
Stack gas Reheater K
No. 6 fuel oil
Fan L
Stack
M
Venturi
Surge tank
Pump
Spray tower
Delay tank
Stack gas reheater
Fan
Settling pond
1/4" limestone rock
Hopper
Conveyor
Surge bin
Weighing feeder
Ball wet grinder
Classifier
N

FIGURE S-2. WET LIMESTONE SCRUBBING

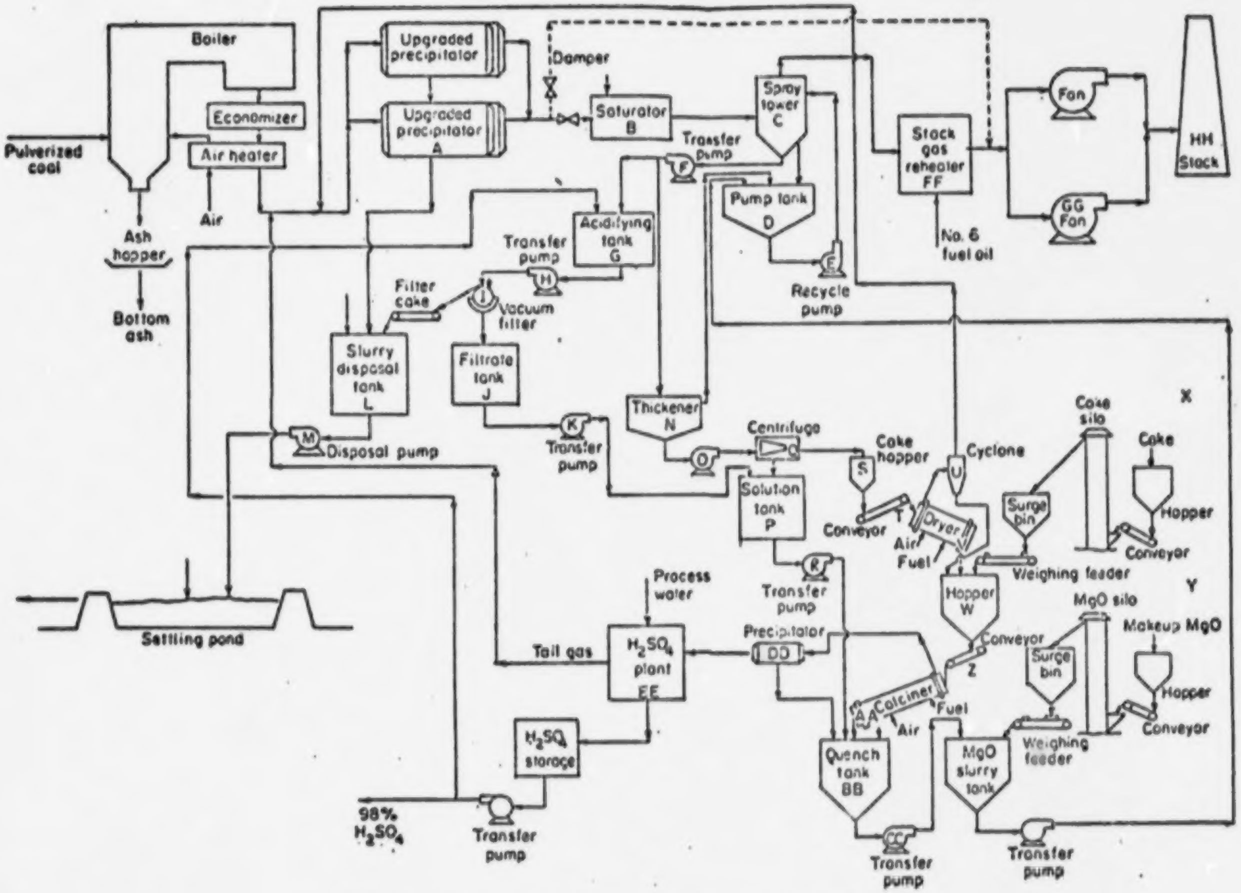
Pulverized coal
Boiler
Economizer
Air heater
Air
Ash hopper
Bottom ash
Upgraded precipitator
Upgraded precipitator A
Damper
Saturator B
Transfer pump
F
Spray tower C
Pump tank D
E
Recycle pump
Stack gas reheater FF
No. 6 fuel oil
Fan
GG Fan
HH Stack
Acidifying tank G
Transfer pump
H
Filter cake
I
Vacuum filter
Slurry disposal tank L
Filtrate tank J
M
Disposal pump
K
Transfer pump
Thickener N
O
Centrifuge
Solution tank P
S
Cake hopper
Conveyor
T
Cyclone
U
Dryer
V
Air
Fuel
Coke silo
Surge bin
Weighing feeder
Coke
Hopper
Conveyor
X
Hopper W
Conveyor
Z
Y
MgO silo
Makeup MgO
Surge bin
Hopper
Conveyor
Weighing feeder
Settling pond
Process water
R
Transfer pump
Precipitator
DD
Tail gas
H_2SO_4 plant EE
H_2SO_4 storage
98% H_2SO_4
Transfer pump
AA
Calciner
Fuel
Air
Quench tank BB
CC
Transfer pump
MgO slurry tank
Transfer pump

FIGURE S-3. MgO SCRUBBING WITH H_2SO_4 RECOVERY

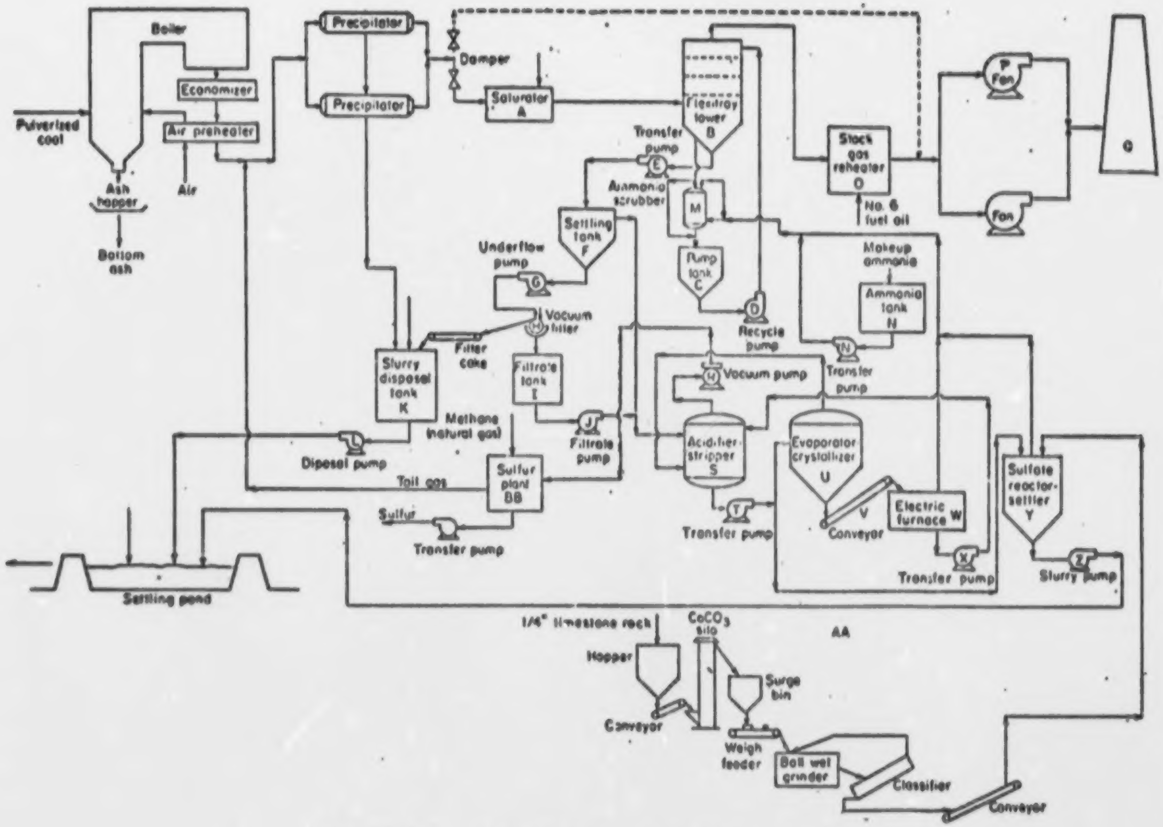
Pulverized coal
Boiler
Economizer
Air preheater
Air
Ash hopper
Bottom ash
Precipitator
Precipitator
Damper
Saturator A
Flexitray tower B
Transfer pump
E
Ammonia scrubber
M
Pump tank C
D
Recycle pump
Settling tank F
Underflow pump
G
Vacuum filter
H
Filter cake
Slurry disposal tank K
Filtrate tank I
J
Filtrate pump
L
Disposal pump
Methane (natural gas)
Sulfur plant BB
Tail gas
Sulfur
Transfer pump
Settling pond
Stack gas reheater O
No. 6 fuel oil
P Fan
Fan
Q
Makeup ammonia
Ammonia tank N
N
Transfer pump
H
Vacuum pump
Acidifier-stripper S
T
Transfer pump
Evaporator crystallizer U
V
Conveyor
Electric furnace W
X
Transfer pump
Sulfate reactor-settler Y
Z
Slurry pump
AA
1/4" limestone rock
Hopper
Conveyor
$CaCO_3$ silo
Surge bin
Weigh feeder
Ball wet grinder
Classifier
Conveyor

FIGURE S-4. AMMONIA SCRUBBING WITH SULFUR RECOVERY

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with the SO_2, which obviously is important in regard to reactant utilization and process equipment requirements. Pearson et al(S-9) state that the effective reactant is calcium bicarbonate formed by reaction of calcium carbonate with dissolved carbon dioxide and postulate the following reactions:

$$CaCO_3 + CO_2 + H_2O \rightarrow Ca(HCO_3)_2 \qquad (S\text{-}1)$$

$$Ca(HCO_3)_2 + SO_2 + H_2O \rightarrow CaSO_3 \cdot 2H_2O\downarrow + 2CO_2\uparrow \qquad (S\text{-}2)$$

$$CaSO_3 \cdot 2H_2O + 1/2\ O_2 \rightarrow CaSO_4\ 2H_2O\downarrow \qquad (S\text{-}3)$$

Oxidation of sulfite is another phase of the process chemistry that also is not well understood. It has been generally considered that oxidation is desirable because if the sulfite is allowed to escape into watercourses it will gradually oxidize there and reduce the oxygen content of the water. Moreover, there is some evidence that oxidation to sulfate is desirable for the prevention of scaling. However, the effect of oxidation on scrubbing efficiency is not known. Several investigators have found the scrubber effluent to contain equal amounts of sulfite and sulfate. Assuming 50 percent oxidation, the overall scrubber reaction per mole of SO_2 is then the sum of Equations S-1 and S-2 plus 50 percent of Equation S-3, or

$$\begin{aligned} CaCO_3 + 2H_2O + SO_2 + 1/4\ O_2 &\rightarrow 1/2\ CaSO_3 \cdot 2H_2O\downarrow \\ &+ 1/2\ CaSO_4 \cdot 2H_2O\downarrow + CO_2\uparrow \qquad (S\text{-}4) \end{aligned}$$

Process Chemistry for MgO Scrubbing with H_2SO_4 Recovery

Slaked MgO reacts with SO_2 in the scrubber to form bisulfite and sulfite. The scrubber is operated at a high enough pH so that all the bisulfite is converted to sulfite. Part of the sulfite is oxidized to sulfate. Assuming 20 percent oxidation of the sulfite, the overall scrubbing reaction is:

$$\begin{aligned} MgO + SO_2 + 0.1\ O_2 + 6.2\ H_2O &\rightarrow 0.8\ MgSO_3 \cdot 6H_2O\downarrow \\ &+ 0.2\ MgSO_4 \cdot 7H_2O\downarrow \qquad (S\text{-}5) \end{aligned}$$

The presence of sulfate in the recovery system is undesirable since an additional treatment is required to reduce the sulfate to sulfite.

The calcination process converts dehydrated magnesium sulfite to sulfur dioxide gas and makes active magnesium oxide for recycle. The dehydrated solids fed to the calciner contain magnesium sulfate which is reduced with coke to sulfite. The overall calcinator reaction is:

$$0.8\ MgSO_3 + 0.2\ MgSO_4 + 0.1\ C \rightarrow MgO + SO_2\uparrow + 0.1\ CO_2\uparrow \qquad \text{(S-6)}$$

In the contact sulfuric acid plant, SO_2 is oxidized to SO_3 over a catalyst and the SO_3 is absorbed in water:

$$SO_2 + 1/2\ O_2 \xrightarrow[\text{catalyst}]{} SO_3 \qquad \text{(S-7)}$$

$$SO_3 + H_2O \rightarrow H_2SO_4 \qquad \text{(S-8)}$$

The overall process reaction can be determined by adding Equations S-5 through S-8 to yield

$$SO_2 + 0.6\ O_2 + 0.1\ C + H_2O \rightarrow H_2SO_4 + 0.1\ CO_2\uparrow \qquad \text{(S-9)}$$

Process Chemistry for Ammonia Scrubbing with Sulfur Recovery

The reactions that occur in the scrubber are very similar to those that occur in MgO scrubbing. Assuming that 75 percent of the bisulfite reacts to form sulfite and that 20 percent of the sulfite oxidizes to form sulfate, the overall scrubber reaction is:

$$\begin{aligned} 1.75\ NH_3 + SO_2 + H_2O + 0.075\ O_2 &\rightarrow 0.25\ NH_4HSO_3 \\ &+ 0.6\ (NH_4)_2SO_3 + 0.15\ (NH_4)_2SO_4 \qquad \text{(S-10)} \end{aligned}$$

The formation of sulfate in the scrubber is undesirable since it must be purged from the recovery system in a way that leads to a loss of product.

The combined acidifier-stripper reaction is:

$$\begin{aligned} &0.6\ (NH_4)_2SO_3 + 0.25\ NH_4HSO_3 + 1.45\ NH_4HSO_4 \rightarrow \\ &\quad 1.45\ (NH_4)_2SO_4 + 0.85\ SO_2\uparrow + 0.85\ H_2O\uparrow \qquad \text{(S-11)} \end{aligned}$$

The decomposition reaction which takes place in the electric furnace is:

$$1.45\ (NH_4)_2SO_4 \xrightarrow[\text{heat}]{} 1.45\ NH_3 + 1.45\ NH_4HSO_4 \qquad \text{(S-12)}$$

The following reaction takes place in the sulfate reactor:

$$\begin{aligned} &0.15\ (NH_4)_2SO_4 + 0.15\ CaCO_3 + 0.15\ H_2O \rightarrow 0.15\ CaSO_4\ \ 2H_2O\downarrow \\ &\quad 0.15\ CO_2\uparrow + 0.30\ NH_3\uparrow \qquad \text{(S-13)} \end{aligned}$$

In the modified Claus plant, SO_2 is catalytically reduced to sulfur by natural gas (methane):

$$2SO_2 + CH_4 \rightarrow 2H_2O + CO_2 + 2S \qquad \text{(S-14)}$$

Side products of the reduction process are carbonyl sulfide and hydrogen sulfide which are made to catalytically react with SO_2 to produce sulfur:

$$2COS + SO_2 \rightarrow 2CO_2 + 3S \qquad (S\text{-}15)$$

$$2H_2S + SO_2 \rightarrow 2H_2O + 3S \qquad (S\text{-}16)$$

The overall process reaction can be determined by adding Equations S-10 through S-14, after multiplying Equation S-14 by 0.425, to yield

$$SO_2 + 0.075\ O_2 + 0.15\ CaCO_3 + 0.425\ CH_4 \rightarrow 0.85\ S$$
$$+ 0.15\ CaSO_4 \cdot 2H_2O\downarrow + 0.575\ CO_2\uparrow + 0.55\ H_2O \qquad (S\text{-}17)$$

Emissions on a Unit Basis

In order to determine the process emissions on a unit basis, arbitrarily chosen as 10^6 Btu of input to the boiler, it is necessary to define the type of fuel burned and to make certain assumptions regarding the process. Emissions were tabulated for two types of coal, eastern and western, and one type of fuel oil with the following typical characteristics:

	Eastern Coal	Western Coal	Fuel Oil
Heating value, Btu/lb	12,000	9,235	18,000
Sulfur content, percent	3.0	0.8	2.9
Ash content, percent	14.4	8.4	0.1

The ash content of the fuel was assumed to end up as 80 percent fly ash and 20 percent bottom ash, and each process was assumed to operate in the closed-loop mode with a 1 percent blowdown rate. The recovery processes were assumed to have a 5 percent loss of regenerated reactants, and in the reduction of SO_2 to form sulfur, each of the side products was assumed to be emitted on the basis of 1 mole percent of the SO_2 entering the modified Claus plant.

The air, water, and solid waste or by-product discharges are summarized for the three stack gas cleaning processes under consideration in Table S-1. This table includes emissions for the years 1975 and 1990 for plants burning eastern coal, western coal, or fuel oil. NO_x discharge and total organic discharges were estimated on the basis of generalized emission factors for pulverized coal and oil-fired boilers compiled by the EPA.(S-10)

The remaining air emissions, as well as the solid waste and by-product emissions, were estimated from a material balance and the chemical stoichiometry of each process. The water emissions were estimated from solubility data and a knowledge of the process flowsheets assuming closed loop operation with a 1 percent blowdown rate and typical impurity levels in the process reactants.

TABLE S-1. ESTIMATED EMISSIONS FROM STACK GAS CLEANING PROCESSES
($lb/10^6$ Btu input)

Emission	Wet Limestone Scrubbing					
	Eastern Coal		Western Coal		Fuel Oil	
	1975	1990	1975	1990	1975	1990
Air Discharges						
Flyash[(a)]	0.0964	0.0482	0.0730	0.0365	4.46×10^{-4}	2.23×10^{-4}
SO_2[(b)]	1.25	0.500	0.436	0.174	0.810	0.324
NO_x[(c)]	0.753	0.601	0.980	0.784	0.734	0.586
Total organic material[(d)]	0.0128	0.0128	0.0166	0.0166	0.0419	0.0419
CO_2	2.59	3.11	0.891	1.07	1.67	2.01
NH_3	-	-	-	-	-	-
COS	-	-	-	-	-	-
H_2S	-	-	-	-	-	-
Water Discharges						
$SO_3^{=}$	1.66×10^{-5}	1.99×10^{-5}	5.71×10^{-6}	6.85×10^{-6}	1.07×10^{-5}	1.28×10^{-5}
$SO_4^{=}$	1.03×10^{-3}	1.24×10^{-3}	3.55×10^{-4}	4.26×10^{-4}	6.65×10^{-4}	7.98×10^{-4}
NH_4^{+}	-	-	-	-	-	-
Dissolved solids	5.66×10^{-3}	6.80×10^{-3}	1.95×10^{-3}	2.34×10^{-3}	3.66×10^{-3}	4.39×10^{-3}
Suspended solids	should be low	should be low	should be low	should be low	should be low	should be low
COD, ppm	4	4	4	4	4	4
pH	6-9	6-9	6-9	6-9	6-9	6-9
Solid Waste and By-Products						
Ash (flyash and bottom ash)	11.9	11.9	9.03	9.03	0.0559	0.0561
$CaSO_4$ sludge	11.6	13.9	4.00	4.80	7.50	9.00
MgO tailings	-	-	-	-	-	-
H_2SO_4	-	-	-	-	-	-
Sulfur	-	-	-	-	-	-

TABLE S-1. (CONTINUED)

Emission	MgO Scrubbing with H_2SO_4 Recovery					
	Eastern Coal		Western Coal		Fuel Oil	
	1975	1990	1975	1990	1975	1990
Air Discharges						
Flyash[(a)]	0.0964	0.0482	0.0730	0.0365	4.46×10^{-4}	2.23×10^{-4}
SO_2[(b)]	1.25	0.500	0.436	0.174	0.810	0.324
NO_x[(c)]	0.753	0.601	0.980	0.784	0.734	0.586
Total Organic Material	0.0128	0.0128	0.0166	0.0166	0.0419	0.0419
CO_2[(d)]	0.259	0.311	0.0891	0.107	0.167	0.201
NH_3	-	-	-	-	-	-
COS	-	-	-	-	-	-
H_2S	-	-	-	-	-	-
Water Discharges						
$SO_3^{=}$	minimal	minimal	minimal	minimal	minimal	minimal
$SO_4^{=}$	1.84×10^{-4}	2.21×10^{-4}	6.33×10^{-5}	7.64×10^{-5}	1.19×10^{-4}	1.43×10^{-4}
NH_4^+	-	-	-	-	-	-
Dissolved solids	5.06×10^{-4}	6.07×10^{-4}	1.74×10^{-4}	2.09×10^{-4}	3.27×10^{-4}	3.92×10^{-4}
Suspended solids	minimal	minimal	minimal	minimal	minimal	minimal
COD, ppm	minimal	minimal	minimal	minimal	minimal	minimal
pH	6-9[(e)]	6-9[(e)]	6-9[(e)]	6-9[(e)]	6-9[(e)]	6-9[(e)]
Solid Waste and By-Products						
Ash (flyash and bottom ash)	11.9	11.9	9.03	9.03	0.0559	0.0561
$CaSO_4$ sludge	-	-	-	-	-	-
MgO tailings	0.117	0.141	0.0404	0.0487	0.0756	0.0913
H_2SO_4	5.87	7.04	2.03	2.42	3.79	4.55
Sulfur	-	-	-	-	-	-

TABLE S-1. (CONTINUED)

Emission	Ammonia Scrubbing with Sulfur Recovery					
	Eastern Coal		Western Coal		Fuel Oil	
	1975	1990	1975	1990	1975	1990
Air Discharges						
Flyash[(a)]	0.0964	0.0482	0.0730	0.0365	4.46×10^{-4}	2.23×10^{-4}
SO_2[(b)]	1.25	0.500	0.436	0.174	0.810	0.324
NO_x[(c)]	0.753	0.601	0.980	0.784	0.734	0.586
Total organic material	0.0128	0.0128	0.0166	0.0166	0.0419	0.0419
CO_2[(d)]	1.49	1.79	0.512	0.615	0.960	1.16
NH_3	0.0875	0.105	0.0301	0.0361	0.0564	0.0675
COS	0.0353	0.0424	0.0122	0.0147	0.0227	0.0273
H_2S	0.0200	0.0240	0.00690	0.00831	0.0129	0.0155
Water Discharges						
$SO_3^{=}$	1.38×10^{-4}	1.66×10^{-4}	4.78×10^{-5}	5.71×10^{-5}	8.94×10^{-5}	1.07×10^{-4}
$SO_4^{=}$	6.44×10^{-4}	7.73×10^{-4}	2.23×10^{-4}	2.66×10^{-4}	4.16×10^{-4}	4.99×10^{-4}
NH_4^{+}	4.60×10^{-5}	5.52×10^{-5}	1.58×10^{-5}	1.91×10^{-5}	2.97×10^{-5}	3.56×10^{-5}
Dissolved solids	1.10×10^{-3}	1.32×10^{-3}	3.80×10^{-4}	4.56×10^{-4}	7.12×10^{-4}	8.55×10^{-4}
Suspended solids	low	low	low	low	low	low
COD, ppm	500	500	500	500	500	500
pH	6-9	6-9	6-9	6-9	6-9	6-9
Solid Waste and By-Products						
Ash (flyash and bottom ash)	11.9	11.9	9.03	9.03	0.0559	0.0561
$CaSO_4$ sludge	1.62	1.94	0.559	0.670	1.04	1.25
MgO tailings	-	-	-	-	-	-
H_2SO_4	-	-	-	-	-	-
Sulfur	1.60	1.92	0.550	0.661	1.03	1.24

(a) Fly ash removal efficiencies are 99.0% in 1975 and 99.5% in 1990.
(b) SO_2 removal efficiencies are 75% in 1975 and 90% in 1990.
(c) NO_x removal efficiencies are 0% in 1975 and 20% in 1990, not including reductions from combustion modifications.
(d) CO_2 emitted only as a result of the scrubbing process chemistry, which is a small fraction of the CO_2 emitted from the combustion process.
(e) Some discharge of acid could occur from operation of the acid plant.

Pollution Controls

Methods

To date, full-scale operating experience on stack gas cleaning processes for coal fired power plants has been rather limited. Union Electric and Combustion Engineering have spent over $3,000,000 on a limestone injection-wet scrubbing system for Meramec Unit 2 but have had to abandon the project because of plugging in the boiler.(S-11) Kansas Power and Light has installed similar systems on Lawrence Units 4 and 5 and, after making very extensive modifications, has just reached the point where they are hopeful of successful operation.(S-12) Commonwealth Edison has installed a limestone wet scrubber on Will County Unit 1 where the limestone is injected into the scrubber circuit rather than the boiler.(S-5) Startup occurred in February 1972, and up to September 11, 1972, Scrubber A had an availability of 32.6 percent and Scrubber B had an availability of 26.0 percent. Scrubbers A and B had a simultaneous availability of only 8.1 percent. However, when the scrubbers were operating under normal design conditions, they removed up to 90 percent of the SO_2.

Other full-scale stack gas cleaning systems that are presently on line at utility company boilers are MgO scrubbing at Boston Edison's Mystic Station Unit 6(S-3) and the Cat-Ox process at Illinois Power Company's Wood River Unit 4.(S-13) The Mystic Station unit has had problems with materials handling and has been limited to no more than 500 to 600 hours of operation in the six months since startup, which occurred in April, 1972. The Wood River unit was placed in operation on September 4, 1972, and information on operating experience is not as yet available.

Cost

The EPA has determined that the gross annualized costs of wet scrubbing processes for stack gas cleaning vary little with process type and range from 2.22 to 2.46 mills/kwhr for the base case described by the second column of Table S-2. These costs do not include credit for the sale of by-product H_2SO_4 or sulfur nor debit for the disposal of these materials. However, the market for these by-products is full of uncertainties and each case has to be examined individually. It is extremely doubtful that a utility would undertake MgO scrubbing without a guaranteed market for the by-product acid.

The EPA has performed a sensitivity analysis of wet limestone scrubbing operating costs which is summarized in Table S-2.(S-14) The most important factor appears to be the sulfur content of the fuel and the least important factor appears to be the option of particulate scrubbing; however, single factors do not reveal the total cost variations. The combination of all factors at the low level and of all factors at the high level gives an operating cost variation from 1.1 to 7.7 mills/hwhr.

The costs listed in Table S-2 were calculated from simple capital and annualized cost equations developed by the EPA.(S-14) The cost range for

TABLE S-2. OPERATING COST-SENSITIVITY ANALYSIS FOR WET LIMESTONE SCRUBBING(S-14)

Parameter	Base	Parameter Range	Cost Range[a] (mills/kwhr)	Percentage Variation[b] Relative to Base Cost
Sulfur content	3.5%	0.7 - 7.0%	1.80 - 3.19	57
Plant size	500 MW	1000-100	2.20 - 3.44	50
Load factor	60%	80 - 40	2.14 - 2.97	34
Indirect costs	70%	70% - 140%	2.46 - 3.08	25
Waste disposal	$3/ton	1 - 5	2.16 - 2.76	24
Retrofit factor	1.25	1.0 - 1.5	2.20 - 2.72	21
Particulate	Scrubbing	No - Yes	2.16 - 2.46	12
Total variation, combined effect of low cost levels and high cost levels			1.08 - 7.66	267

(a) All other parameters are held at base conditions while the parameter in question is varied over its range.

(b) Cost at base case is 2.46 mills/kwhr.

a given parameter was determined by holding all other parameters at base conditions while the parameter in question was varied over its range. The appropriate values for each parameter were than used in the EPA cost equations to determine an operating cost in mills/kwhr for each case.

The sensitivity analysis permits an estimate to be made of the cost of wet limestone scrubbing on an oil-fired boiler. For this case, the sulfur content of the fuel is 2.9 percent and there is no need for particulate scrubbing, with all other factors remaining the same as the base case. The result is 2.0 mills/kwhr for an oil-fired boiler as compared to 2.4 mills/kwhr for an eastern-coal-fired boiler and 1.8 mills/kwhr for a western-coal-fired boiler. For comparison purposes, the estimated operating cost for wet limestone scrubbing at Will County is 4.5 mills/kwhr.(S-5) The operating parameters for Will County are a 170 MW unit with particulate scrubbing burning 4 percent sulfur coal at a capacity factor of 70 percent and a sludge disposal cost of $7 per ton.

Recent statements regarding capital cost illustrate the need to define the basis for the estimate to avoid confusion. Capital cost for the limestone scrubbing system at Will County has been estimated to be $96/kw. Part of this high cost is attributable to difficulties associated with a difficult retrofit job and overtime paid to meet regulatory deadlines. Also part is attributable to the cost of a relatively expensive sludge disposal system. The capital cost for the scrubber installation at Mystic Station (MgO scrubbing) is estimated at $24/kw not including indirect overhead charges and escalations.(S-4) Also, the scrubber installation at Mystic Station does not include the cost of a sulfuric acid plant and associated equipment. Capital cost for the Cat-Ox process at Wood River is estimated to be $73/kw.(S-13) TVA estimates indicate a cost of $54 to $63/kw for a proposed wet limestone scrubber at Widow's Creek which compares with a cost of $49/kw for the same plant calculated using the EPA capital cost equation.(S-14)

The EPA(S-15) has estimated that the expected application of stack gas cleaning on the basis of clean fuel availability is 30 to 50 percent of existing coal and oil-fired capacity. Up to 80 to 90 of the power plants in the Northeastern United States could install stack gas desulfurization processes with a cost at or below the premium for the clean fuels if projected clean fuel costs materialized.

Areas of Uncertainty

The above discussion is predicted on many assumptions and, therefore, must be considered as a "rough cut" at the problem rather than a definitive analysis. It may be helpful, at this time, to recapitulate the major assumptions as follows:

1. Wet limestone, MgO, and ammonia or alkali scrubbing are typical of stack gas cleaning processes to be applied during 1975 to 1990.

2. The removal efficiencies for SO_2, NO_x, and fly ash will be linear functions of time with SO_2 ranging from 75 to 90 percent removal, NO_x from 0 to 20 percent removal, and fly ash from 99 to 99.5 percent removal, all within the 1972 to 1990 time period.

3. The ash content of the fuel ends up as 80 percent fly ash and 20 percent bottom ash.

4. The scrubbing processes will be operated in a closed-loop mode with a 1 percent blowdown rate.

5. The recovery processes will have a 5 percent loss of regenerated reactants.

6. Each of the side products in the reduction of SO_2 to form sulfur will be emitted at the rate of 1 mole percent of the SO_2 entering the sulfur plant.

7. The EPA cost data are reasonably correct.

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APPENDIX T

FLUIDIZED-BED COMBUSTION OF COAL AND OIL

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APPENDIX T

FLUIDIZED-BED COMBUSTION OF COAL AND OIL

Introduction

Fossil fuel consumption is expected to triple in the next 20 years. Supplies of low sulfur fuel will be inadequate to meet projected demand so that some other method for controlling sulfur emissions will be needed. Flue gas cleaning systems will provide part of the pollution control which will be needed in the years immediately ahead but gas cleaning will be costly and will add significantly to the cost of power production. In the 1990 to 2000 period, gasification systems which produce cleaned low Btu gas from coal may find significant amounts of application but it will be necessary to solve serious technical and economic problems before this can come to pass. Even if all problems are solved with reasonable success, neither flue gas cleaning, coal gasification nor any combination of the two is likely to provide a totally satisfactory means for timely prevention of emissions of all three pollutants (sulfur oxides, nitrogen oxides, and fly ash) normally associated with fossil fuel combustion. Modified combustion systems which prevent emissions of these pollutants would eliminate the need for add-on gas cleaning systems and could in some instances find application in the period when the longer term solutions such as coal gasification are being perfected. Fluidized-bed combustors have demonstrated potential for development as systems which could make this kind of unique contribution to control of pollution in the next 20 years. Because of the attractive antipollution characteristics of fluidized-bed combustors, what is now the Division of Control Systems (DCS), Office of Research and Monitoring of the Environmental Protection Agency, since 1968 has supported work to develop fluidized-bed combustion systems which would burn coal or residual oil with minimum pollution from sulfur oxides, nitrogen oxides, and particulates. The DCS program has been conducted by Federal and Nonfederal contractors in the United States and United Kingdom and work has been in cooperation with workers in other countries. Results to date have confirmed the potential usefulness of systems which burn high sulfur fossil fuels in fluidized beds of limestone or dolomite. Numerous process variations have been studied for both oil and coal combustion and two have been demonstrated to be especially attractive. In one, coal would be burned in a pressurized boiler in a combined gas-steam turbine cycle. In the other, residual oil would be burned at atmospheric pressure in a system which would be retrofitted to existing boilers. These two variations have been considered in the present study and are discussed below and in the main body of the report.

Pressurized Fluidized-Bed Combustion

Background

The present concept of pressurized fluidized-bed combustion of coal has evolved from work supported by EPA-DCS and carried out by a number of organizations in the United States and England. Westinghouse has used the data generated by bench-scale and pilot-plant studies to do design studies which indicate that a fluidized-bed system operated at 10 atmospheres in a combined cycle where both gas and steam turbines are used would offer many significant advantages both as an air pollution control system and as an improved combustion-boiler system. From the standpoint of an air pollution control system the process offers the following features:

(a) A high level of SO_2 control (95 percent) due to:

1. A good limestone-SO_2 reaction temperature, sufficiently low that dead-burning of the sorbent is not such a serious problem as it sometimes can be in conventional boilers.
2. Good contacting between the sorbent particles and the combustion gases.
3. Longer residence time of the sorbent in the combustion zone particularly in the case of lime-bed systems.

(b) Reduced NO_x emissions (80 percent) because of:

1. The relatively low operating temperatures, reducing the fixation of atmospheric nitrogen.
2. In pressurized systems particularly, the reduction of NO_x in the presence of SO_2 and of CO to 50-140 ppm (as demonstrated by the British Coal Utilization Research Association).

(c) Potential for reduced particulate emissions (99 percent) especially fine particulates.

From the standpoint of a combustion system, this process offers:

(a) High bed-to-tube heat transfer coefficients within the bed (50 Btu/hr ft^2 F^o in a conventional boiler).

(b) High volumetric heat release rates (500,000 Btu/hr per ft^3 of furnace volume, or possibly even higher, compared to 20,000 Btu/hr/ft^3).

(c) Consequently, a smaller boiler with less tube surface (some estimates indicate that a 600 MW atmospheric pressure fluidized-bed boiler might be 1/2 to 2/3 the size of a conventional unit). Pressurized operation offers even further size reductions.

(d) Lower capital costs (10 to 20 percent lower than conventional boilers) and lower power costs (5 to 15 percent lower).

(e) Possibly higher supercritical steam conditions in utility fluidized-bed boilers (to perhaps 1200 F, 4000 psig).

(f) Ability to burn poorer grades of fuel more readily than can conventional boilers.

(g) Reduced ash fouling and high-temperature corrosion as a result of the lower operating temperatures.

Cost/Benefit

Some preliminary estimates indicate that fluidized-bed power stations will cost \$20 to \$50 per kilowatt less than conventional power plants with stack gas cleaning equipment. The timely development of such plants can produce savings in new power plant investments of \$600,000,000 to \$1,500,000,000 per year in 1985 and beyond. The total development cost of the fluidized-bed combustion system will be approximately \$75,000,000. By using \$1,000,000,000 per year as a reasonable estimate of the annual savings in capital investment resulting from application of the system, the cost/benefit for the program for the period 1985 to 2000 is calculated to be:

$$\text{Cost/Benefit} = \frac{\$15 \text{ billion}}{\$.075 \text{ billion}}$$

Fluidized-bed power plants offer other potential benefits. Initially, their overall efficiency will equal that of conventional plants, about 38 percent; however, with further development of gas and steam turbine technology, an efficiency up to 50 percent can be achieved. Overall reductions in power costs from 10-30 percent along with air pollution abatement will result from the successful development of pressurized fluidized-bed combustion. As an added benefit, thermal discharge of power plants to water courses will be reduced by 10 to 60 percent.

Development Program

Past work on bench and pilot-scale equipment is to be continued and expanded to include the operation of an integrated (combustion system plus limestone regeneration) 0.63 MW pilot plant which is to be put on stream early in 1973. This unit will be designed by ESSO R&E and will have flexibility to permit continuous operation over a wide range of variables. Data from this unit and other on-going projects will be used for design of a 10 to 20 MW plant. It is expected that the commercial capabilities of the process will be demonstrated in the 1974-1977 period and that design work on the 200 MW demonstration plant will begin in 1975. The project will end with a completed demonstration study by 1981.

Description of Process

The process as it is presently conceived is described in detail in Reference(T-1) which reports the results of design studies done by Westinghouse for the EPA. In this study, plant sizes of 300 MW and 600 MW were considered. Figure T-1 shows a schematic diagram of the plant power cycle. Figure T-2 is a plot plan of steam generators and accessory equipment, and Figure T-3 shows the 300 MW combined-cycle plant-site plot plan.

Atmospheric Pressure Fluidized-Bed Oil Gasification

Background

Pilot-scale experimental work on combustion of residual oil in fluidized beds of limestone has been conducted by Esso Ltd. (U.K.) under Contract with the EPA-DCS. Design data have been supplied by Esso to Westinghouse (also under Contract with EPA) who has done conceptual design studies and evaluation of commercial prospects. The most promising concept to date involves application of the system to production, on-site, of a low sulfur fuel gas suitable for combustion in conventional boiler systems. A system of this type appears to be acceptable either with or without regeneration of limestone. The pollution control advantages offered by such a system are as follows:

(a) Sulfur removal efficiencies up to 95 percent are possible for the reasons cited in the discussion of the pressurized coal combustion system.

(b) Nitrogen oxide emissions can be limited to 150 ppm for the reasons cited in the discussion of pressurized coal combustion.

(c) Particulate emissions will be higher than those from oil or gas fired systems but will be controllable using high efficiency dust collectors. Also there is evidence to suggest that some of the most offensive particulates (such as sodium and vanadium) will be removed in the fluidized bed so that the particulates which do escape will be less objectionable than those from conventional oil fired systems.

Advantages over conventional boilers with flue gas cleaning, the only alternative where low sulfur fuels are not available, are as follows:

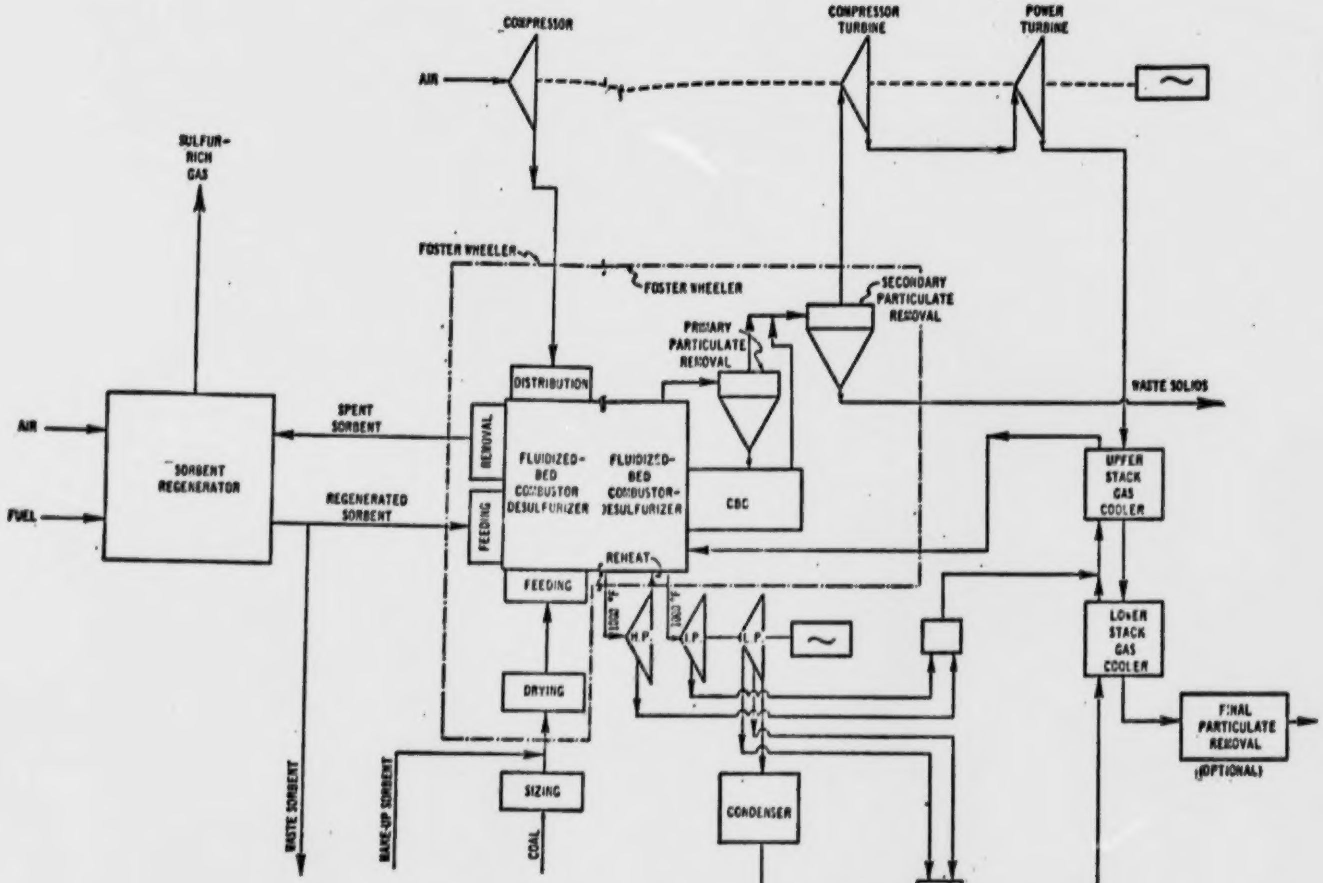

COMPRESSOR
COMPRESSOR TURBINE
POWER TURBINE
AIR
~
SULFUR-RICH GAS
FOSTER WHEELER
FOSTER WHEELER
SECONDARY PARTICULATE REMOVAL
PRIMARY PARTICULATE REMOVAL
DISTRIBUTION
WASTE SOLIDS
AIR
FUEL
SORBENT REGENERATOR
SPENT SORBENT
REGENERATED SORBENT
REMOVAL
FEEDING
FLUIDIZED-BED COMBUSTOR DESULFURIZER
FLUIDIZED-BED COMBUSTOR-DESULFURIZER
CBC
UPPER STACK GAS COOLER
REHEAT
FEEDING
1000 °F
1000 °F
H.P.
I.P.
L.P.
~
LOWER STACK GAS COOLER
DRYING
FINAL PARTICULATE REMOVAL
(OPTIONAL)
WASTE SORBENT
MAKE-UP SORBENT
SIZING
COAL
CONDENSER

FIGURE T-1. SCHEMATIC DIAGRAM, PLANT POWER CYCLE

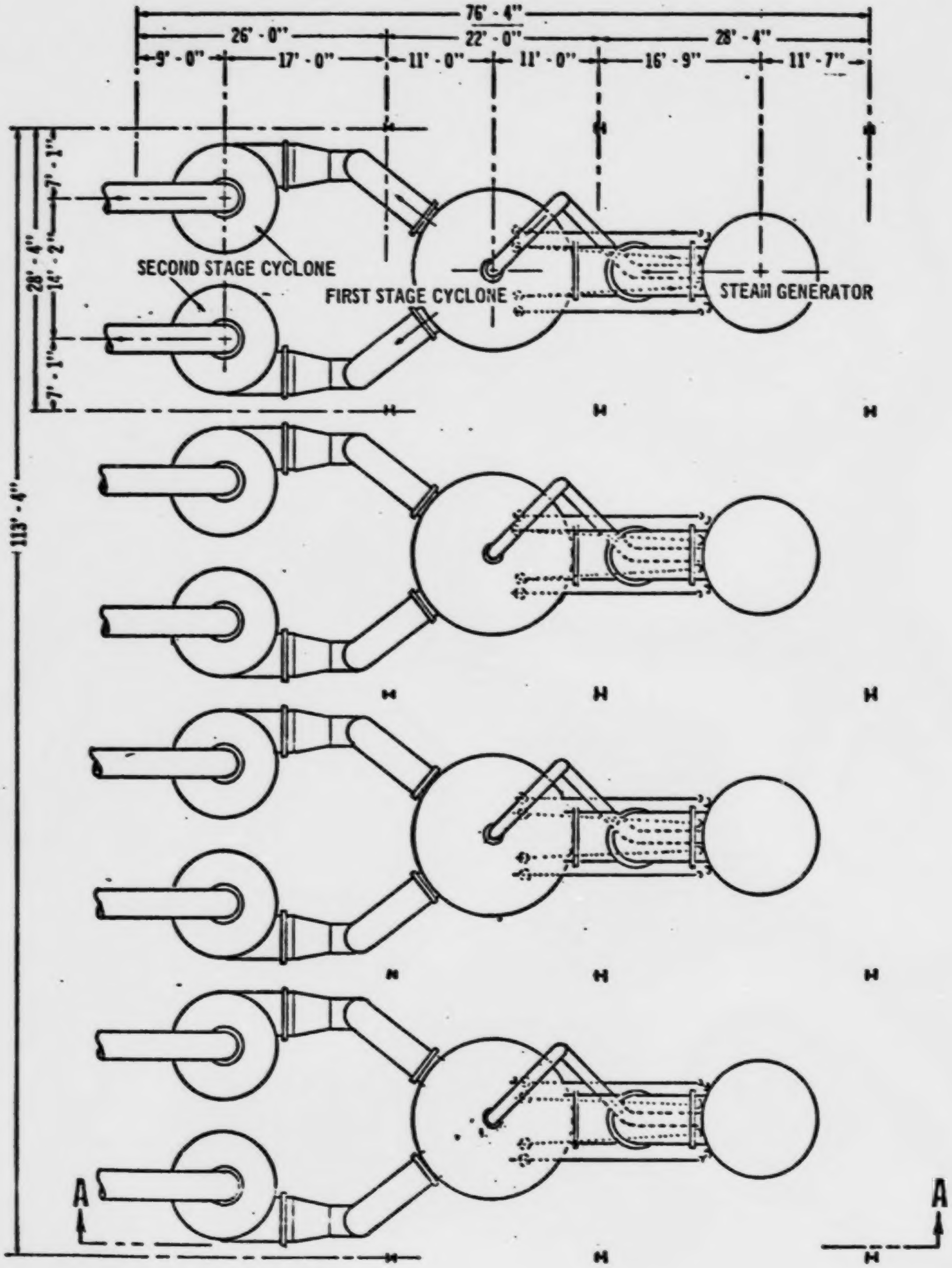
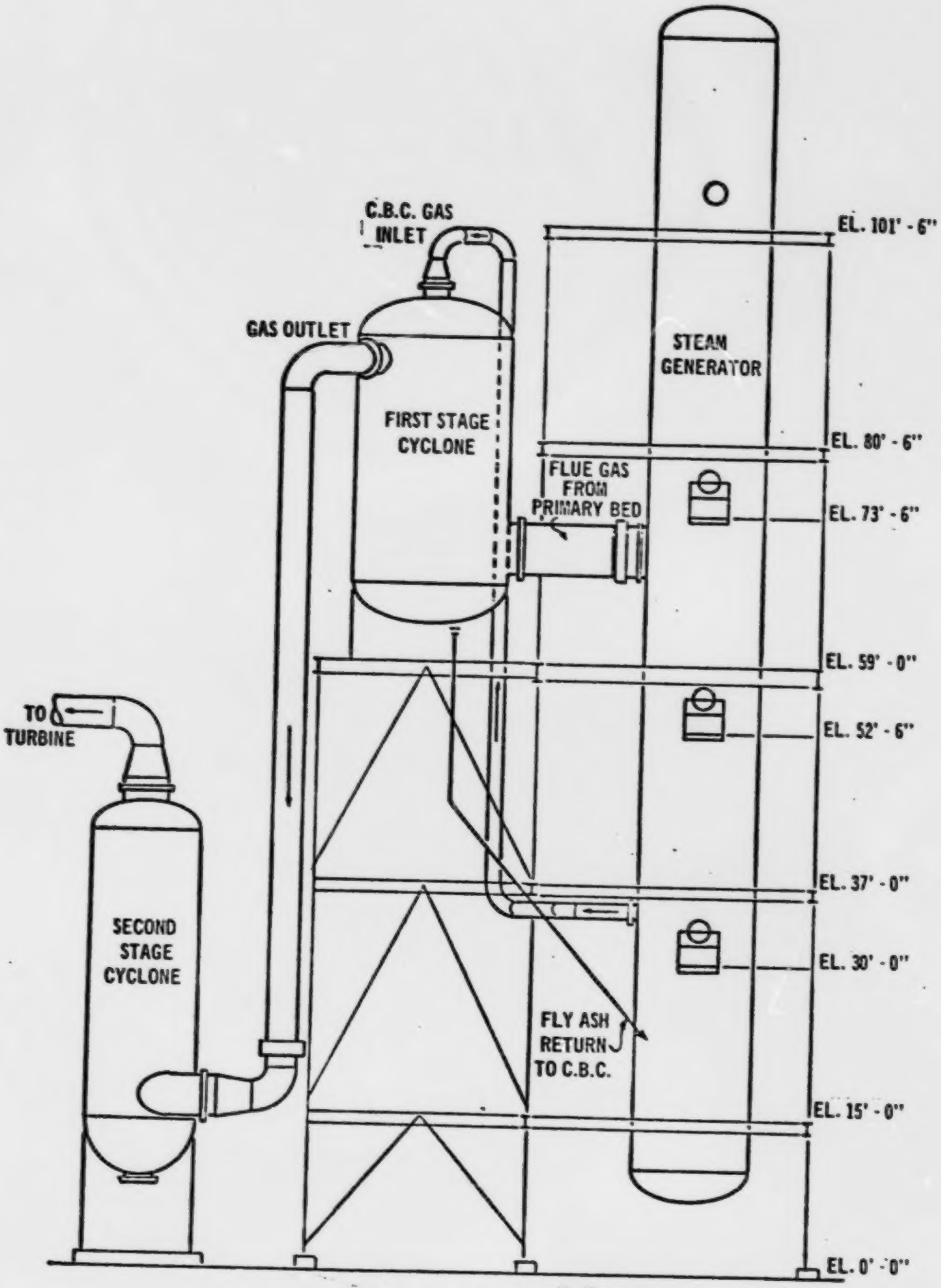

76' - 4"
26' - 0"
22' - 0"
28' - 4"
9' - 0"
17' - 0"
11' - 0"
11' - 0"
16' - 9"
11' - 7"
7' - 1"
28' - 4"
14' - 2"
7' - 1"
113' - 4"
SECOND STAGE CYCLONE
FIRST STAGE CYCLONE
STEAM GENERATOR
A
A

FIGURE T-2. PLOT PLAN, STEAM GENERATORS AND ACCESSORY EQUIPMENT FOR A 300-MW COMBINED-CYCLE PLANT (SHEET 1 of 2)


C.B.C. GAS INLET
GAS OUTLET
STEAM GENERATOR
EL. 101' - 6"
FIRST STAGE CYCLONE
EL. 80' - 6"
FLUE GAS FROM PRIMARY BED
EL. 73' - 6"
EL. 59' - 0"
TO TURBINE
EL. 52' - 6"
EL. 37' - 0"
SECOND STAGE CYCLONE
EL. 30' - 0"
FLY ASH RETURN TO C.B.C.
EL. 15' - 0"
EL. 0' - 0"

SECTION **A-A**

FIGURE T-2. PLOT PLAN, STEAM GENERATORS AND ACCESSORY EQUIPMENT FOR A 300-MW COMBINED-CYCLE PLANT (SHEET 2 of 2)

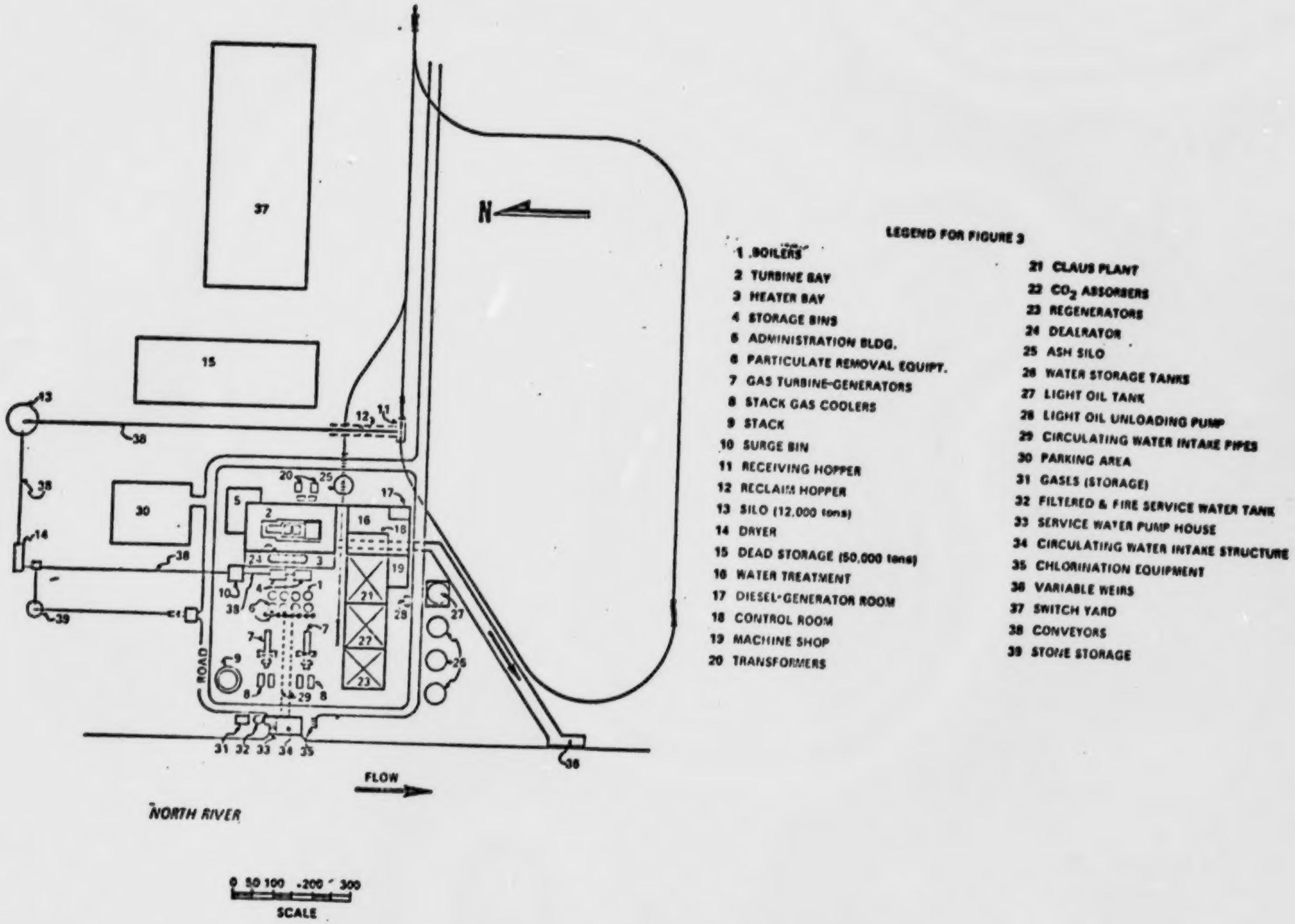

LEGEND FOR FIGURE 3
1 BOILERS
2 TURBINE BAY
3 HEATER BAY
4 STORAGE BINS
5 ADMINISTRATION BLDG.
6 PARTICULATE REMOVAL EQUIPT.
7 GAS TURBINE-GENERATORS
8 STACK GAS COOLERS
9 STACK
10 SURGE BIN
11 RECEIVING HOPPER
12 RECLAIM HOPPER
13 SILO (12,000 tons)
14 DRYER
15 DEAD STORAGE (50,000 tons)
16 WATER TREATMENT
17 DIESEL-GENERATOR ROOM
18 CONTROL ROOM
19 MACHINE SHOP
20 TRANSFORMERS
21 CLAUS PLANT
22 CO2 ABSORBERS
23 REGENERATORS
24 DEALRATOR
25 ASH SILO
26 WATER STORAGE TANKS
27 LIGHT OIL TANK
28 LIGHT OIL UNLOADING PUMP
29 CIRCULATING WATER INTAKE PIPES
30 PARKING AREA
31 GASES (STORAGE)
32 FILTERED & FIRE SERVICE WATER TANK
33 SERVICE WATER PUMP HOUSE
34 CIRCULATING WATER INTAKE STRUCTURE
35 CHLORINATION EQUIPMENT
36 VARIABLE WEIRS
37 SWITCH YARD
38 CONVEYORS
39 STONE STORAGE
N
ROAD
FLOW
NORTH RIVER
0 50 100 200 300
SCALE

FIGURE T-3. SITE PLOT PLAN, 300-MW COMBINED-CYCLE PLANT

(a) The levels of control of the three pollutants discussed above are higher than can be attained with conventional systems.

(b) The capital cost of a retrofit, once-through gasification system, is expected to be 50 to 70 percent less than for a retrofit wet-scrubbing system.

(c) Corrosion and fouling problems in boiler and collection system are less as SO_x is collected in the fluidized bed.

(d) The system is more compact; it uses crushed limestone eliminating the need for pulverizers which are required for wet limestone scrubbing. Also no flue gas preheat is needed and the dry solids disposal problem is easier to handle than the sludge disposal required by wet limestone scrubbing system.

Cost/Market

The retrofit process capital cost is expected to be 50 to 70 percent less than for a retrofit wet scrubbing system and fuel added-cost for a retrofit system is expected to be 30 to 50 percent less than that for retrofit wet scrubbing, low-sulfur oil, or desulfurized oil. The process appears to be the most attractive near-term possibility for boilers less than 600 MW where residual oils are available. Initial markets would be the East and West coast and in parts of the Southwest where gas is limited. The comparative values for cost and emissions for conventional boilers with low sulfur fuel and oil gasification systems are shown in Table T-1. The total cost for the development program, including a demonstration plant, is about $4.7 million. A cost-benefit analysis is now under way but has not been completed.

Development Program

The present conceptual designs are based on bench and pilot-scale testing on a 750 kw development plant. A demonstration plant program is now planned. It would be concluded with collection of data from a demonstration plant of about 100 MW. Preliminary design of the demonstration unit was completed in 1972. Construction is expected to start about September, 1973, with start of operation to begin in September, 1974. Complete evaluation of the demonstration plant will be completed by mid-1976.

Process Description

Two modes of operation are possible for atmospheric pressure fluidized-bed oil gasification; regenerable and once-through. The preferred mode will depend on local factors such as cost of limestone, etc. A complete process description including the assumed design conditions is presented in Reference T-2. A schematic flowsheet for the two basic modes of operation is given in Figure T-4.

TABLE T-1. ASSESSMENT OF FLUIDIZED-BED OIL GASIFICATION/DESULFURIZATION

Basis: 3% Sulfur, 90% Sulfur Removal, 600 MW Capacity, 80% Load Factor

	Low-Sulfur Oil	Stack Gas Cleaning	Oil Gasification	
			Regenerative Operation	Once-Through Operation
COST				
Capital, \$/kW				
New	---	25-40	12-15	8-10
Retrofit	(a)	40-75	22-27	18-22
Fuel Adder, ¢/10^6 Btu				
New	25-35	11-14	9.5-16.0	9-10.5
Retrofit	25-35[a]	14-20	11-18	10.5-12.5
EFFICIENCY (THERMAL)	---	0.95-0.98	0.89-0.96[b]	0.96-0.97[b]
ENVIRONMENTAL FACTORS				
SO_2, (lb/10^6 Btu)	0.35	0.45	0.35	0.35
NO_x, (lb NO_2/10^6 Btu)	0.40	0.8	0.16	0.16
Particulates, (lb/10^6 Btu)	0.06	0.05	0.02-0.2[c]	0.02-0.2[c]
Solid Waste, ft^3/MW-day	---	25	15	45
S REMOVAL				
Stone	NA		Limestone	Limestone
Ca/S	NA		~ 15[d]	3.0
Make-up Ca/S	NA		1.0	NA

[a] Equipment modifications are required when converting from gas or coal to low sulfur oil.

[b] Overall efficiency is dependent on mode of temperature control.

[c] 0.02 figure based on installing electrostatic precipitator (ESP).
0.2 figure based on installing high efficiency cyclone before burners and no ESP.

[d] Ca/S rate dependent on regenerator temperature control scheme.

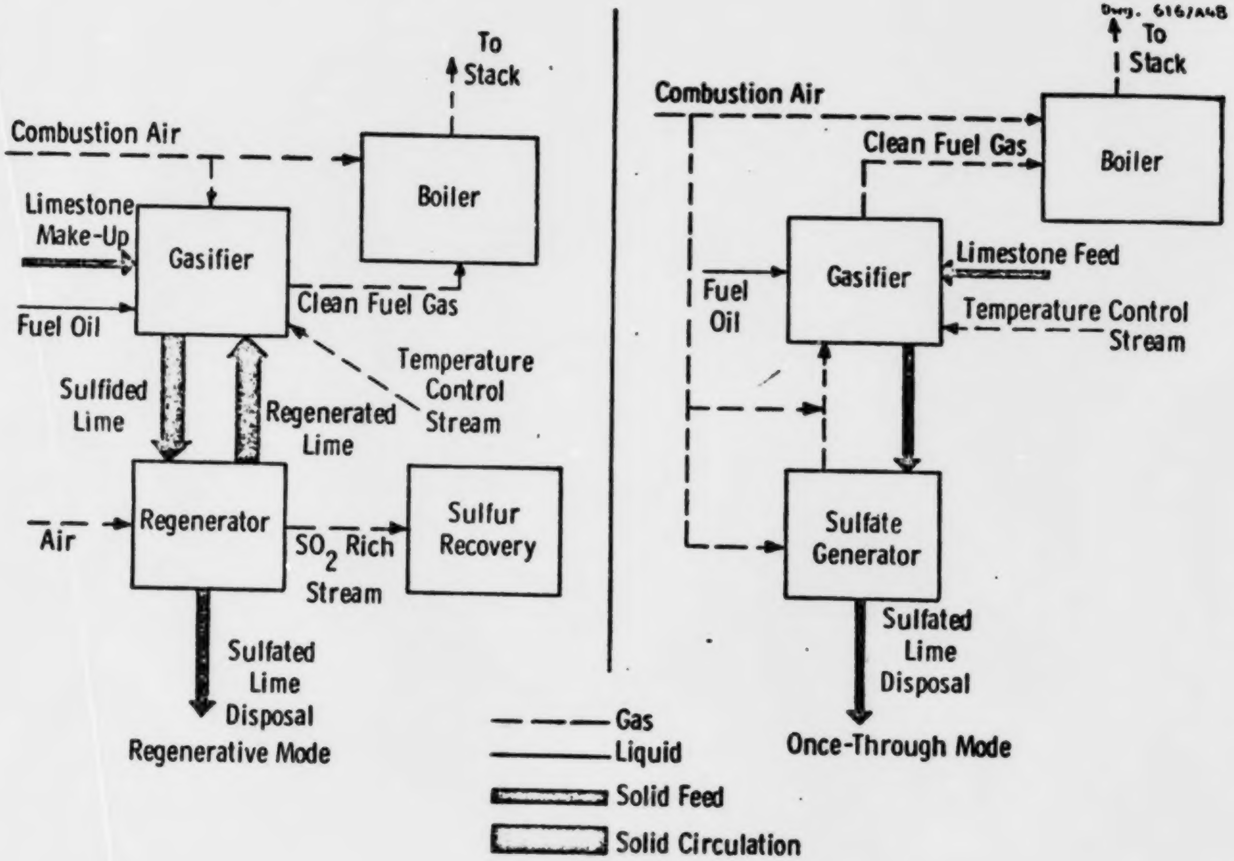

Combustion Air
To Stack
Boiler
Limestone Make-Up
Gasifier
Fuel Oil
Clean Fuel Gas
Temperature Control Stream
Sulfided Lime
Regenerated Lime
Air
Regenerator
SO2 Rich Stream
Sulfur Recovery
Sulfated Lime Disposal
Regenerative Mode
Dwg. 616A48
To Stack
Combustion Air
Clean Fuel Gas
Boiler
Fuel Oil
Gasifier
Limestone Feed
Temperature Control Stream
Sulfate Generator
Sulfated Lime Disposal
Once-Through Mode
Gas
Liquid
Solid Feed
Solid Circulation

FIGURE T-4. MODES OF OPERATION

APPENDIX U

SOLID WASTE UTILIZATION

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APPENDIX U

SOLID WASTE UTILIZATION

The United States produces large quantities of solid wastes which contain combustible material. These solid wastes create a disposal problem in terms of cost and environment factors, yet they represent a potential fuel reserve. Widespread use of solid waste as a fuel could have the dual advantage of conserving other fuels and accomplishing disposal of the wastes. Background information relating to the utilization of solid waste has been compiled in a recent EPA report.(U-1) The following section is quoted from that report.

Background

Potential Energy of U.S. Solid Wastes

In 1968, the USPHS, Solid Waste Program, made a national survey of solid waste practices. It was conservatively estimated that the United States was producing over 3.5 billion tons of solid wastes every year and in the household, municipal and commercial sectors alone, collection and disposal were costing $3.5 billion annually, while industry was spending about $1 billion each year. Both increasing population and increased per capita generation were predicted.

Table U-1, taken from the National Survey, shows the estimated annual quantities of solid wastes generated in 1967.

TABLE U-1. ANNUAL GENERATION OF SOLID WASTE (1967)

Household, commercial and municipal	250	million tons
Industrial solid wastes	110	" "
Agricultural wastes and crop residues	550	" "
Animal wastes (manure)	1500	" "
Mining wastes	1100	" "

The potential of solid wastes as an energy source (exclusive of radioactive materials) is dependent on its heating value, thus in determining available energy, moisture and noncombustibles must be taken into consideration. Extreme variation in both moisture content and noncombustible fraction occurs within waste types and even greater variation is noted between solid waste types.

Community Solid Wastes. Table U-2 shows the typical range in composition of residential-commercial (community) solid wastes based on published reports(U-2) and discussions with incinerator designers.

TABLE U-2. PHYSICAL AND CHEMICAL CHARACTERISTICS OF INCINERATOR SOLID WASTE(a)

Constituents	% by weight (as received)
Proximate analysis:	
Moisture	15-35
Volatile matter	50-65
Fixed Carbon	3- 9
Noncombustibles	15-25
Ultimate analysis:	
Moisture	15-35
Carbon	15-30
Oxygen	12-24
Hydrogen	2- 5
Nitrogen	0.2-1.0
Sulfur	0.02-0.1
Noncombustibles	15-25
Higher heating value	Btu per lb (as received) 3,000-6,000

(a) Principally residential-commercial waste excluding bulky waste.

While the table shows a Btu range of 3000 to 6000, the "as received" refuse most often has a high heat value between 4000 and 4500 Btu per lb. It is significant to note that the heat value of community solid waste is expected to increase. With increased use of plastics and paper, the value could increase by 500 Btu per lb by 1980.

If all community solid wastes were collected, the potential heat energy in the United States would be 2,100 trillion Btu per year. This is based on current generation of 250 million tons per year and an average high heat value of 4200 Btu per lb.

Industrial Solid Wastes. In determining the potential heat value of industrial solid wastes, estimated in 1967 at 110 millions tons per year, it is necessary again to recognize that published information on the chemical characteristics of industrial waste is practically non-existent.

Based on discussions with EPA personnel who have conducted limited surveys, it can be expected that this waste would have substantially higher value than community refuse due to increased content of wood, paper and plastics plus absorbed oils and greases--thus an average value of 5200 Btu per lb is considered conservative. On this basis, if all industrial solid wastes were collected, the potential annual heat value of the fuel would be 1,144 trillion Btu per year.

Manures, Crop and Forest Residues. The 1968 National Survey of Solid Waste Practices estimated agricultural wastes, animal manure, and forest waste production at 2,050 million tons annually. These wastes generally have high moisture contents and much of the waste is left uncollected. The 1970 production of animal manures, forest residues and fruit tree prunings on a dry weight basis has a heat content of 3,506 trillion Btu(U-3).

The total energy theoretically available annually from United States solid wastes, based on 1967 and 1970 production, is summarized below.

Waste Source	Production, million tons	Average Heat Value, Btu	Available Energy trillion Btu
Household, commercial, and municipal (community)	250	4200(a)	2,100
Industrial solid wastes	110	5200(a)	1,144
Manures, crop and forest residues	232	7600(b)	3,506

(a) "As received" with inerts and natural moisture.

(b) Average value - moisture-free. (1970 Production)

The total power of all United States municipal (community) solid wastes, based on 250 million tons per year generation and an average "as received" heat value of 4200 Btu/lb, theoretically would be:

$$\frac{2100 \times 10^{12}\ \text{Btu/yr}}{(9500\ \frac{\text{Btu}}{\text{kwhr}}\ \ (1000\ \frac{\text{KW}}{\text{MW}})\ (8000\ \text{hr/yr})} = 27{,}600\ \text{MW}$$

The total United States power generating capacity in 1972 (power plants only) is roughly 350,000 MW. The power was derived from the following sources in the approximate amounts--coal - 170,000 MW; oil - 23,000 MW; natural gas - 60,000 MW; hydro - 50,000 MW; with nuclear making up most of the remainder(U-4). Therefore, the theoretical maximum contribution of household, commercial and municipal solid wastes would be:

$$\frac{27{,}600}{350{,}000} \times 100 = 8\%$$

All industrial solid wastes, manures, crop wastes and forest residues are equivalent to 4,650 trillion Btu and would theoretically have the potential to supply 17 percent of the current United States power needs. Thus all United States solid wastes would theoretically provide the fuel to meet 25 percent of the nation's current power requirements.

* * *

Municipal Refuse for Steam Generation

Combustion of municipal refuse for power and steam generation has evolved to a well-developed art in Europe over the past 40 years. About 50 percent of refuse is cellulosic, thus forming an easily combustible though heterogeneous fuel. Two German plants have now been built in the United States: Chicago-Northwest; 1600 tons/day, 150,000 lb steam/hour, 22 MW electrical equivalent(U-5), and Harrisburg, Pennsylvania; 720 tons/day, 70,000 lb steam/hour, 10 MW equivalent(U-6). Both of these plants produce only steam, not electrical power. The refuse is burned on moving grates in furnaces lined with vertical steam generator tubes similar to conventional coal-fired power plants. High-efficiency electrostatic precipitators clean the exhaust. This trend will continue and accelerate in the United States. Although these are large incinerators, their potential electrical output is small.

If all the waste collected in our large cities could be used as fuel and if the heat produced could be used for district heating and cooling, "most" of these energy loads in the central business district of these cities could be satisfied. These are very big if's. Investment costs for clean steam plants and for underground steam or hot water mains are awesome. Nevertheless, this new United States trend to follow the European lead will continue.

Municipal Refuse As A Power-Plant Fuel

Much consideration has been given to recovery of heating values in refuse. About 10 percent of the energy required for a typical city could be recovered from its refuse. One approach to recovery of heat from refuse has been to build expensive incinerators which burn the heterogeneous refuse with little or no pretreatment. This approach has certain disadvantages. The equipment is costly, and relatively complicated. Corrosion and air pollution are difficult to control. Skilled operators, often unavailable to municipal organizations, are required.

An alternative approach which has been considered in recent years is to process the refuse to remove noncombustibles, and shred and promote homogeneity so that the material is suitable for firing in combination with fossil fuels in power boilers. This approach has many patent advantages, namely:

(1) The cost of preparation equipment is small compared to modern incinerators. A complete preparation plant designed for recovery of a fuel and ferrous metals would probably cost about $5/ton of capacity as compared to $10 or more per ton for an incinerator.

(2) The net cost of operation for a plant producing fuel for burning in an existing boiler has been estimated at $5 to $6 per ton without the credit for recovered heat. With refuse disposal costs now running around $10 and more per ton in many cities, this would give a savings of about $4 to $5 per ton over alternative methods. This represents an annual savings of $1.5 to $2.0 million dollars per year for a city of 500,000 producing 1000 ton/day of refuse.

(3) The fuel values which can be recovered are significant. At 40¢ per million Btu's, an annual return of over $1.0 million per year would be realized from a 1000 ton/day plant. This would reduce the processing cost to $1 to $2 per ton.

(4) All equipment required for effective refuse processing systems is commercially available so that no development work would be required for a preparation plant.

(5) In most municipalities the demand for energy substantially exceeds the availability of energy in the refuse produced. This situation favors the possibility of combined firing of coal and refuse. A city of 500,000 would produce about 1000 ton/day of refuse. At 4200 Btu/lb this would provide about 10 percent of the fuel for a 500 MW boiler.

(6) The combined firing scheme which is favored by logistics tends to minimize the potential problems associated with feeding and firing of the refuse in a boiler. Studies have indicated that firing refuse in quantities up to 10 to 20 percent of the total Btu input should not seriously interfere with boiler operation. Potential objectionable components do not appear to be present in quantities which will impact seriously on the normal mode of operation for the boiler.

The City of St. Louis, in a cooperative effort with the EPA, initiated a program based on this approach in May of 1972(U-7, U-8). The trash is shredded and magnetically separated and fed into a pulverized coal steam boiler plant. About 300 tons of refuse per day are consumed in this way and this accounts for 10 percent of the energy supplied to the boiler.

Other Forms of Municipal Refuse Utilization

Current schemes to produce gas or oil by pyrolysis of refuse are too embryonic to gage their promise. Even if successful they will not alter significantly the energy produced nor the environmental emission of energy recovery(U-9).

Environmental Burden

To produce 1000 MW electricity will require a plant burning about 73,000 tons of refuse per day. The refuse shredder and magnetic separator could salvage roughly 3,000 tons per day of steel scrap (assuming about 4 or 5 percent of the refuse is recoverable).

Emissions to the air from water-walled units will be:

Particulate	0.1 lb/million Btu input	0.18 is allowed by EPA(U-5)
Sulfur Dioxide	0.9 lb/million Btu input	No limit for incinerators. For coal boilers limit is 1.2(U-10)
Nitrogen Oxides	0.5 lb/million Btu input (Estimate)	No limit for incinerators. For coal boilers limit is 0.7
Chlorides (as HCl)	500 ppm (0.06/million Btu)	No limits have been set(U-11)

A major problem will be protecting the boiler tubes from corrosion by increasing amounts of chlorides created by incineration of chlorinated plastics(U-12).

Water pollutants discharged: None, assuming appropriate processing because the effluent is small in volume and can be thoroughly treated.

Solid residue from combustion (including fly ash) to be deposited in sanitary 7300 tons/day (assuming 90 percent weight reduction). 15,000 cu yd/day (assuming 95 percent volume reduction).

The atmospheric and liquid waste emissions will be minimal, less than the important current standards. Particulate emission will be only about 1/10 that of current municipal incinerators. Land use for solid residue disposal will be about 1/20 that now required for sanitary landfill of "raw" refuse. Surface water leaching from burned residues is at present an ill-defined concern.

The environmental emission of producing power from solid waste should be considered in light of other waste disposal alternatives.

(1) Straight incineration would probably produce equivalent emissions, if controlled. However, power production will probably occur in large, efficient, easier to control boilers with auxiliary coal firing. Therefore, net pollution potential is less than with incineration.

(2) Landfill would require 10 to 20 times more solid waste disposal volume than incineration with power production. Of course, there are few significant air emissions from landfill.

Therefore, the net environmental emission of power production from solid wastes is negligible, considering alternative disposal methods.

Research Costs - Refuse

Considerable research will be required for development of assured power boiler designs to combat corrosion. Zinc and lead in refuse are important corrosive agents when tied in with the chlorides(U-9). Confining the operation to low-temperature steam production appears to eliminate corrosion. To generate power efficiently higher temperatures are required; hence, ways should be found to protect high-temperature boiler tubes.

This corrosion research will require of the order of $1 to $5 million per year, accelerating as the technology develops. Total estimated boiler corrosion research cost: $20 million in 10 years.

Current research on the surface water polluting potential of leaching of incinerator residue should be continued. Estimated research cost on water pollution potential of incinerator residues: $5 million total over 10 years.

Utilization of Organic Portion of Solid Wastes

The amount of animal wastes produced in the United States exceeds total municipal solid waste by a factor of two; hence, it is potentially a large energy source if burned or somehow converted to fuel. However, the environmental hazard of thus destroying this potential source of humus in the soil instead of realizing its soil benefication potential should also be carefully evaluated. Assuming that our total organic waste output is appropriate to consider as an energy source, even some of this is infeasible for conversion because of its remoteness from the centers of energy demand.

Assuming that one-half of this total organic waste is available for conversion by some process to a clean fuel, the potential fuel value as oil would be about 90 million barrels(U-13). This would be about 1.5 percent of the United States 1971 crude oil demand. The reference just quoted also states "The economic feasibility of converting organic wastes to oil or gas has not as yet been proven". Although the potential addition to our total energy supply is small, the opportunity to reduce also our landfill disposal problem makes this potential attractive enough to justify detailed analysis and small-scale pilot investigation.

The potential for saving of space required for sanitary landfill can be a significant beneficial impact of pyrolysis, gasification, or incineration. In metropolitan areas this already is a critical factor because nearby sites are used up and neighboring communities frown on "importing environmental impacts from others". A rule of thumb states that land requirement of 3/4 to 1-1/2 acres per year per 10,000 population is required if the average depth of the compacted refuse is seven feet(U-14). Using an average of one acre per year, if all of our population were served by sanitary landfills, the area required would be 20,000 acres per year. Potentially, pyrolysis, incineration, or gasification to produce useful fuels or heat or electrical energy could cut that landfill requirement to well under 10,000 acres per year, depending on the degree of resource recovery applied during shredding or other preparation of the waste before processing.

Many small-scale attempts have been made to show that useful gas and combustible liquids can be derived economically from solid wastes(U-9). None of these has been successful where tried in large scale. Two major new efforts in this direction were announced in September, 1972, when EPA announced $6-million for partial support of a 1000-ton per day, $14-million pyrolysis demonstration plant for the city of Baltimore producing gas for steam generation, using a process developed by Monsanto-Eniro-Chem. Operation is to start June, 1974; hence, it will be at least 1977 before feasibility is fully evaluated.

At the same time, September, 1972, EPA announced a $2.9-million demonstration grant to San Diego County for a $4-million plant to pyrolyze 200 tons of solid waste per day to produce fuel oil and to reclaim glass and metal. The system was developed by Garrett Research and Development Company. This plant is scheduled to operate in December, 1974.

Thus, if recovery as gas or oil from the organic portion of municipal waste is feasible at full scale, we are now nearer to knowing that than ever before. It will require several years to determine the outcome.

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APPENDIX V

NUCLEAR FISSION SYSTEMS

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APPENDIX V

NUCLEAR FISSION SYSTEMS

Introduction

Battelle Pacific Northwest Laboratories participated with Battelle-Columbus Laboratories in a study conducted for the Environmental Protection Agency, Office of Research and Monitoring. The purpose of the study was to assess the comparative emissions in the United States from the various fuel sources and energy cycles through 1990. These data are needed to provide the bases for setting policy regarding Federal actions required to meet future demands for energy.

The alternate energy supplies considered commercially viable in the 1975 to 1990 time period are: (1) coal, (2) oil, (3) natural gas, and (4) fission. There are currently five fission power plant concepts being developed. These are

- Light Water Reactor (LWR)
- High-Temperature Gas-Cooled Reactor (HTGR)
- Liquid Metal Fast Breeder Reactor (LMFBR)
- Gas-Cooled Breeder Reactor (GCBR)
- Molten-Salt Breeder Reactor (MSBR)

The LWR and the HTGR are commercially viable, in that they are commercially available to the electric power industry. With the national commitment to developing the LMFBR, it is expected that this type of power plant will be commercially applied in the latter part of this time period. The GCBR and the MSBR are being developed as backup technologies for the nuclear power industry and are not expected to reach commercial application in the 1975 to 1990 time period. Therefore, these two concepts are not included in this assessment, rather they are treated with the analyses of advanced energy technologies and are reported in Appendix W of this report.

All forecasts made to date show continued increases in the amount of electricity consumed in the United States over this time period and in the number of nuclear power plants built to supply that electricity. If these forecasts hold true, then there will be a corresponding increase in the amount of radionuclides generated in meeting this electrical demand. The amount of radionuclides released to the environment also is expected to increase even though improved radwaste systems are adopted which would reduce the release rates. This study forecasts the quantity of radionuclides released during 1975, 1980, 1985, and 1990.

The quantities of radionuclide wastes from the LWR power reactor industry for 1967, 1970, 1975, and 1980 were previously forecast in Phase I of a study(L-1) conducted for the U.S. Atomic Energy Commission. The forecast of this document is based on the same general assumptions with some modifications of input data and can be considered a continuation of that forecast.

Technical Approach

A combination of forecast data for the electrical power industry and general material balances for the nuclear segment of that industry are used to estimate the quantities of waste for 1975, 1980, 1985, and 1990. The relevant material flows in and out of the nuclear power industry are identified and quantified by type and location, with emphasis placed on determining the final disposition of waste materials.

The general flow of radioactive materials through the power reactor system was divided into nine steps for the uranium cycle and eight steps for the thorium cycle. These 17 steps are presented schematically in Figure V-1. For each step, a material balance was made to determine relevant inputs and outputs, including the quantities, physical forms, and disposal system. The material balances for each process are presented in flowcharts and tables. Five of the steps involved two distinctly different processes having different effluents and, thus, two sets of data were prepared. (As an example, separate tables were prepared for the acid leach and carbonate leach uranium mills activities.) The waste burial steps for the uranium and thorium cycles were combined. Each of the resultant steps is described as a separate industry and the data for each are presented in subsequent sections.

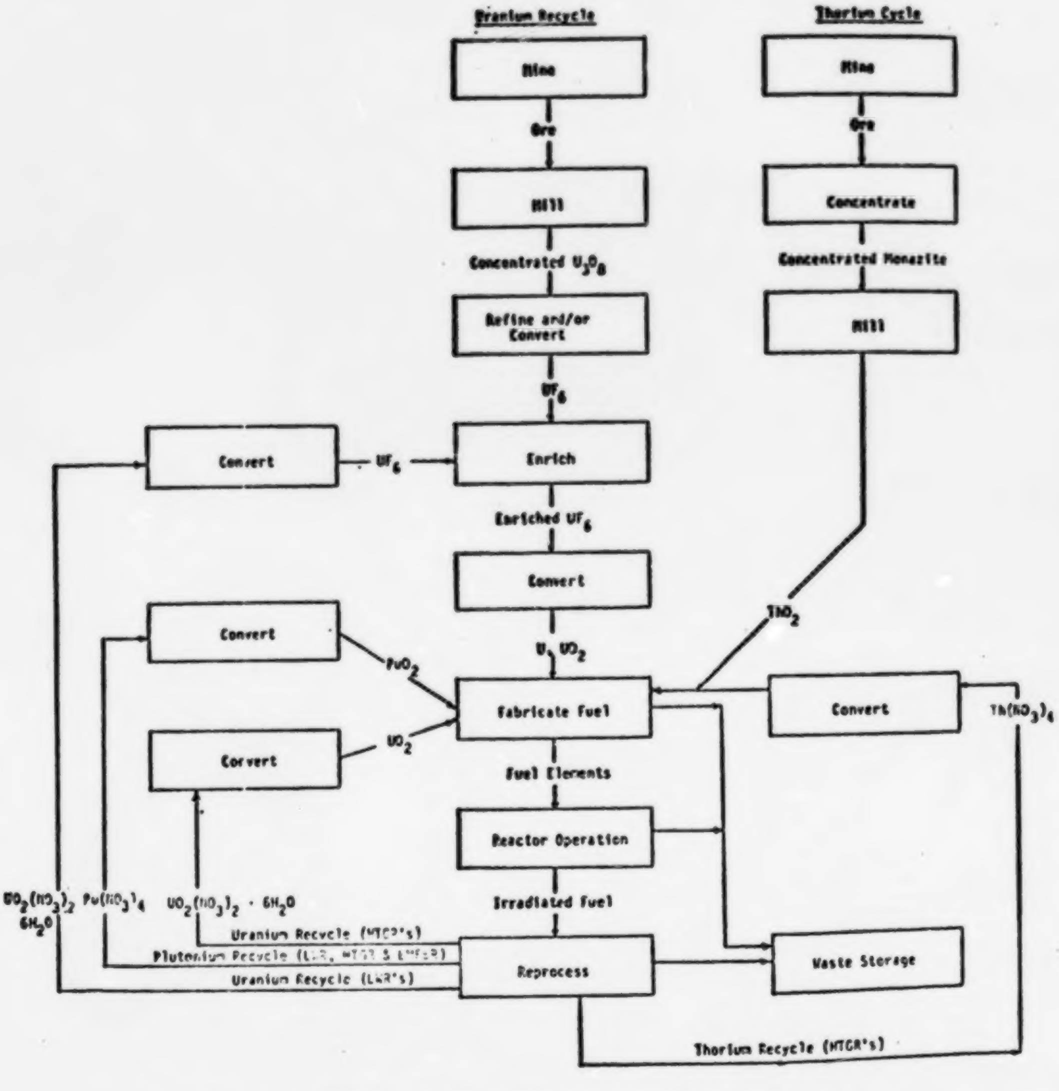
The waste produced by each process was assumed to be directly proportional to the activity level throughputs for 1967 and 1970 and are taken from AEC records and Nuclear Industry, 1970. Projections were made using the Linear Programming Model of the U.S. Power Economy(V-2) which has been used in previous studies for the USAEC,(V-3) and the ISOPRO computer code(V-4) which calculate throughputs based on installed capacity.

Assumptions Made in This Study

Because this was a preliminary study, several simplifying assumptions were made which are listed here.

- The AEC is now providing numerical guidelines on design objectives for light water cooled reactors which would carry out its policy of keeping radioactivity in effluents to levels which are as low as practicable. The cited projected levels for reactors built after 1980 reflect anticipated technological improvements in radwaste treatments.

- It is anticipated that numerical guidelines also will be forthcoming



Uranium Recycle
Thorium Cycle
Mine
Ore
Mill
Concentrated U3O8
Refine and/or Convert
UF6
Mine
Ore
Concentrate
Concentrated Monazite
Mill
Convert
UF6
Enrich
Enriched UF6
Convert
ThO2
Convert
PuO2
U, UO2
Fabricate Fuel
Convert
Th(NO3)4
Convert
UO2
Fuel Elements
Reactor Operation
UO2(NO3)2 6H2O
Pu(NO3)4
UO2(NO3)2 · 6H2O
Irradiated Fuel
Uranium Recycle (HTGR's)
Plutonium Recycle (LWR, HTGR & LMFBR)
Uranium Recycle (LWR's)
Reprocess
Waste Storage
Thorium Recycle (HTGR's)

FIGURE V-1. MATERIAL FLOW IN NUCLEAR (FISSION) FUEL CYCLE

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on design objectives for fuel reprocessing plants to keep their radiation releases and resultant radiation exposure as low as practicable. The projected levels reflect some anticipated technological improvements in waste treatment systems for power and reprocessing plants.

- The quantities quoted for radiological emissions in this report are given as total activity (curies) released. The effects of these releases, which depend on the particular nuclides involved, are excluded in this study. Similarly, the occupational hazards are excluded.

- No attempt was made to anticipate any changes in the standards or estimate any costs that might be involved in meeting them.

- The primary assumptions applying to two or more processes are:

1. The study covers only the commercial nuclear power industry, including all related portions of the fuel cycle.

2. Only LWR's, HTGR's, and LMFBR's were included in the study.

3. LWR's and LMFBR's operate only in the uranium fuel cycle. Plutonium recycle was included. HTGR's operate only on the thorium cycle. Oxide fuels are used for all reactors.

4. Only gaseous diffusion enrichment facilities are used assuming a tails assay of 0.2 percent U^{235} .

5. No target irradiations were considered, or the recovery of special products (i.e., Np^{237}, Cs^{137}).

6. The physical limits of the power reactor system for each type of waste and product are as follows:

Type of Waste or Product	System Physical Limit
Airborne	Physical boundary of plants
Waterborne	Physical boundary of plants
Surface-stored wastes	Physical boundary of plants
Burial wastes	Burial ground
Production	Shipping facilities

7. The radwaste treatment systems used in this study reflect anticipated technological improvements in power reactor radwaste systems.

8. Activation of permanent reactor equipment was not determined. No waste disposal due to decommissioning of reactors and reprocessing plants is included.

9. Possible accidental releases of radioisotopes during shipments were not included.

10. Solidified high-level wastes are to be shipped to permanent storage five years after reprocessing.

11. The use and disposal of radioisotopes for research and medical applications were not included.

12. Available economic and technical data were used. Special analyses were not made to develop new data. 1970 costs were used for operating and capital costs.

13. No throughput for foreign use is included.

Because information was not readily available in the short time permitted for this report, capital and operating costs were not developed for many of the waste treatment systems used in the nuclear industry. General systems for which no cost data were developed were: sanitary wastes, nonradioactive solid wastes, and nonradioactive chemicals discharged to the air, land, and water. The reason is that the costs for such systems are small in relation to the total costs of waste treatment systems. The components of the nuclear industry for which no costs were developed are as follows:

Industry Component	Waste System
U Mining	Mine Ventilation Systems Low-Grade Ore Disposal
U Milling	Ventilation Systems Tailings Disposal
Th Milling	Solid and Liquid Wastes
Enrichment	Airborne Wastes Liquid-Borne Wastes
Surface Burial	Capital Costs

The radiological releases at these stages of the nuclear fuel cycle are small in comparison to those at the fabrication, reactor operation, and reprocessing stages.

Summary

Estimates have been made of the quantity of effluent expected from the projected utilization of nuclear power reactor plants to meet the electrical energy demand during the period 1975 to 1990. These estimates are made assuming normal plant operating conditions. On the basis of the time allotted for completing the study, the emphasis was placed upon identifying and quantifying the release of radiological effluents in the nuclear fuel cycle. A very preliminary study was made of some of the other effluents which impact the environs and these are also reported.

Nuclear Demand and Fuel Requirements

Using historical data from 1965 to the present, a constant growth rate of 7.18 percent was used for projecting electrical demand up to 1980. Using a mix of other data and other energy projections, growth rates of 6.6 percent per year and 5.6 percent per year were used for the decades 1980 to 1990 and 1990 to 2000, respectively. To project the nuclear requirements, it was assumed that the nuclear plants would be base load plants with fossil plants built after 1980 being used for load following. Further, it was assumed that no fossil plants would be built after 1990. Based upon these assumptions, nuclear plants will produce roughly 19/29/41/54 percent of the total installed capacity for the years 1975/1980/1985/1990. If construction schedules for nuclear plants continue to slip and/or no major new markets for electricity appear in this time period, these demand values may be considered upper estimates. These estimates of nuclear power requirements were used to define the nuclear fuel requirements and the throughputs for each stage of the nuclear fuel cycle.

Emissions

Estimates of the quantity of radioisotopes released to air, water, and land receptors were made using the calculated throughputs required to meet the demand schedule for each stage of the nuclear fuel cycle. These are summarized in Tables V-1, V-2, and V-3 for air, water, and land receptors, respectively. Also shown in the tables are the other emissions which must be studied to determine the total emissions. Where data on these nonradiological emissions were immediately available, they are included in Tables V-1 to V-3.

Throughout this report the amounts of radioactive wastes are reported as curies of radioactivity. However, the total number of curies should not be interpreted as a measure of the radiation hazard presented by the various waste streams. Radiation hazard estimates require knowing the quantity, chemical, and physical form for each nuclide released to the environment.

Control Mechanisms and Costs

A great deal of attention is being and has been given to controlling the dispersal of wastes from the nuclear industry to minimize the risks to people and environs.

From considerations of the radiological emissions given in Tables V-1 through V-3, it is evident that the major amounts of radioactive effluent release occur at the reprocessing plant, the power reactor plant, and the fuel fabrication plant. Therefore, the study has been concentrated on investigation of control mechanisms and associated costs for these three stages of the nuclear fuel cycle.

TABLE V-1. SUMMARY OF EMISSIONS--AIR RECEPTORS

Stage of Cycle	Parameter	Year 1975	1980	1985	1990
U Mining	Radiological, Ci(a)				
	Particulate & Gas				
	Thermal				
U Milling	Radiological, Ci	5,000	9,000	16,000	25,000
	Particulate & Gas				
	Thermal				
Th Mining & Milling	Radiological, Ci	0	0	0	0
	Particulate & Gas				
	Thermal				
U Conversion	Radiological, Ci	0	0	0	0
	Particulate & Gas				
	Thermal				
U Enrichment	Radiological, Ci	.3	.5	.8	1.3
	Particulate & Gas				
	Thermal				
Fuel Fabrication	Radiological, Ci	.56	.86	1.41	2.79
	Particulate & Gas				
	Thermal				
Reactor Operation	Radiological, Ci	9.4×10^{6}	2.0×10^{7}	2.4×10^{7}	2.9×10^{7}
	Particulate & Gas				
	Thermal	32(b)	100	253	504
Fuel Reprocessing	Radiological, Ci	1.0×10^{7}	1.7×10^{7}	1.9×10^{7}	2.2×10^{7}
	Particulate & Gas				
	Thermal	25(c)	62	100	190
Conversion	Radiological, Ci	Included in Reprocessing			
	Particulate & Gas				
	Thermal				
Waste Disposal	Radiological, Ci	0	0	0	0
	Particulate & Gas	0	0	0	0
	Thermal				
Totals	Radiological, Ci	1.94×10^{7}	3.7×10^{7}	4.3×10^{7}	5.1×10^{7}
	Particulate & Gas				
	Thermal				

(a) Cu, curies of radioactivity..

(b) Heat in gigawatts.

(c) Heat in megawatts.

TABLE V-2. SUMMARY OF EMISSIONS--WATER RECEPTORS

Stage of Cycle	Parameter	Year			
		1975	1980	1985	1990
U Mining	Radiological, Ci(a)				
	Chemical & Solid				
	Water Usage				
	Thermal				
U Milling	Radiological, Ci	1.2	2.4	4.7	8.1
	Chemical & Solid				
	Water Usage				
	Thermal				
Th Mining & Milling	Radiological, Ci	0	0	0	0
	Chemical & Solid				
	Water Usage				
	Thermal				
U Conversion	Radiological, Ci	.4	.7	1.2	1.9
	Chemical & Solid				
	Water Usage				
	Thermal				
U Enrichment	Radiological, Ci	2.2	4.1	6.4	10.5
	Chemical & Solid				
	Water Usage				
	Thermal				
Fuel Fabrication	Radiological, Ci	13.2	19.8	32.5	64.5
	Chemical & Solid				
	Water Usage				
	Thermal				
Reactor Operation	Radiological, Ci	2.7×10^{5}	8.0×10^{5}	1.5×10^{6}	2.4×10^{6}
	Chemical & Solid				
	Water Usage				
	Thermal	74×10^{3}(b)	132×10^{3}	196×10^{3}	305×10^{3}
Fuel Reprocessing	Radiological, Ci	2×10^{4}	2×10^{4}	2×10^{4}	2×10^{4}
	Chemical & Solid				
	Water Usage	2,600(c)	12,000	20,000	35,000
	Thermal	25(b)	60	100	190
Conversion	Radiological, Ci	Included in Reprocessing			
	Chemical & Solid				
	Water Usage				
	Thermal				
Waste Disposal	Radiological, Ci	0	0	0	0
	Chemical & Solid	0	0	0	0
	Water Usage	0	0	0	0
	Thermal	0	0	0	0
Totals	Radiological, Ci	2.7×10^{5}	8.0×10^{5}	1.5×10^{6}	2.4×10^{6}
	Chemical & Solid				
	Water Usage				
	Thermal				

(a) Ci, curies of radioactivity, where blanks exist, no evaluations were made.

(b) Heat in megawatts.

(c) Gallons/minute.

TABLE V-3. SUMMARY OF EMISSIONS--LAND

Stage of Cycle	Parameter	1975	1980	1985	1990
U Mining	Radiological, Ci(a)				
	Chemical & Solid(b)	1.3×10^{8}	2.4×10^{8}	4.5×10^{8}	7.7×10^{8}
	Land Usage(c)	1,193	2,013	3,439	5,080
U Milling	Radiological, Ci	21,000	38,000	65,000	10.1×10^{4}
	Chemical & Solid				
	Land Usage				
Th Mining & Milling	Radiological, Ci	13	42	120	230
	Chemical & Solid				
	Land Usage				
U Conversion	Radiological, Ci	31	53	92	145
	Chemical & Solid				
	Land Usage				
U Enrichment	Radiological, Ci	0	0	0	0
	Chemical & Solid				
	Land Usage				
Fuel Fabrication	Radiological, Ci(e)	2×10^{5}	1.4×10^{6}	2.6×10^{6}	6.2×10^{6}
	Chemical & Solid(d,e)	1.9×10^{4}	3.4×10^{4}	5.9×10^{4}	1.0×10^{5}
	Land Usage-Waste(c)	1	1	1	2
Reactor Operation	Radiological, Ci(e)	6×10^{5}	1.5×10^{6}	2.8×10^{6}	5.2×10^{6}
	Chemical & Solid(d,e)	6×10^{5}	1.5×10^{6}	2.8×10^{6}	5.2×10^{6}
	Land Usage-Waste(c)	12	30	50	100
Fuel Reprocessing	Radiological, Ci(e)	2.9×10^{5}	1.5×10^{6}	2.9×10^{6}	1.3×10^{8}
	Chemical & Solid	2.6×10^{5}	6.8×10^{5}	1.1×10^{6}	2.2×10^{6}
	Land Usage-Waste	5	14	22	46
Conversion	Radiological, Ci	Included in Reprocessing			
	Chemical & Solid				
	Land Usage				
Waste Disposal (High Level)	Radiological, Ci	0	1.3×10^{9}	3.4×10^{9}	5.5×10^{9}
	Chemical & Solid	0	4,290(d)	11,220	18,180
	Land Usage				
Totals	Radiological, Ci	1.1×10^{6}	1.3×10^{9}	3.4×10^{9}	5.5×10^{9}
	Chemical & Solid				
	Land Usage				

(a) Ci, curies of radioactivity, where blanks exist, no evaluations were made.

(b) Cubic yards of waste rock from open pit and underground mining.

(c) Acres of land required/year.

(d) Ft^3 of solid waste/year.

(e) Shipped to offsite licensed contractor.

Reactor. The reactor waste treatment system is designed to collect all gases, liquids, and solids containing radioactivity and treat them to minimize radiation releases to the environment. A treatment system is provided for each. Although there will be some variations in the waste treatment systems for each reactor type, LWR's, HTGR's, and LMFBR's, these differences are expected to be minor and consist primarily of chemical reaction systems for neutralizing or precipitating the liquid waste streams.

The average costs (1970) for radioactive waste treatment systems for a 1000 MWe (megawatts, electrical power) LWR reactor were $2,611,000 capital cost and $38,430 per year operating cost. Forecasting future waste facility capital costs is difficult because the policy of "as low as practicable" is not quantified. We estimate that the installation for "as low as practicable systems" is about $15 million per reactor and the operating costs will be about $500,000 per year.

In addition to radionuclide emissions, heat rejection from nuclear power plants is of concern. The waste heat from a power plant is released either to a water body or to the atmosphere. The costs for heat dissipation systems depend on the thermal efficiency of the plant and the cooling system used. Typical costs for once-through cooling to water bodies range from $7 to $15 million; evaporative type cooling systems range from $15 to $22 million; and dry cooling systems range from $35 to $50 million. The cost of future control mechanisms for reducing thermal discharges could range from 0 to $30 million assuming the additional cost is that relative to the once-through-cooling-to-fresh-water cost ($7 million).

Fuels Reprocessing Plant. The reprocessing plant waste treatment systems consist of gas, liquid, and solid treatment systems. The LMFBR, HTGR, and LWR reprocessing plant waste treatment systems can be considered to be similar even though the processes are quite distinct. The primary sources of waste are: the fission productions separated from the thorium, uranium, and plutonium recycle streams, the transplutonium isotopes, small percentages of the uranium, thorium, and plutonium, and activated or contaminated processing material and corrosion products.

The costs incurred from the waste treatment facility are not very sensitive to the process used. For a 5 ton per day reprocessing plant, using 1970 costs, the waste treatment facility total capital cost is estimated to be $25 million. Annual operating costs are estimated to be $3 million per year. It is not unreasonable to assume that "as low as practicable' will become the guidelines for controlling releases from reprocessing plants in the future. It is assumed that releases of radioactive gas to the atmosphere will have to be controlled and the estimated costs for gas treatment facilities are $7 million capital costs and $1 million per year for operating costs.

Fuel Fabrication. All fabrication plants can be treated as being essentially similar as far as radioactive wastes and waste treatment are concerned. The principal wastes are airborne particulate which are controlled with filtered ventilation systems, and scrap which must be disposed of.

The average capital and operating costs for air treatment systems for a 5 ton a day plant are $2.2 million and $93 thousand per year, respectively. The average cost for water disposal is estimated at $19,000 per year. Capital costs for water disposal systems are estimated at $224,000. Applying as low as practicable releases to the fabrication industry could impose some additional control mechanisms and costs; however, no estimates have been made of these at this time.

Transportation. Since the nuclear fuel cycle has numerous industrial stages between the extraction of ore to deposit of radioactive wastes there are numerous steps required in transporting the materials between these various stages. Railroads are the primary mode of transporting nuclear materials in the nuclear power industry with shipments by truck being the secondary mode. The principal means of water transportation would be transcontinental freighter. In some steps of the process, the shipments may not go off-site.

The quantities of nuclear materials that will be shipped in these steps for the years 1975, 1980, 1985, and 1990 were estimated. In general, except for accidents, the impacts of shipments of nuclear materials are identical to transportation of any other material. It has been assumed that no releases occur during the transport of nuclear materials between process steps of the fuel cycle simply because we have assumed normal operational conditions. The impact of accidents has not been evaluated since this would require a statistical analysis of the frequency and severity of accidents for similar types of materials.

Experience to date indicates that the regulations now applicable assure a trivial impact to the environment. The AEC and others are currently conducting statistical evaluations of the frequency and severity of accidents and the attendant risk for shipments of spent fuel, recovered plutonium and wastes. Assuming an accident would occur, a ranking of materials from most hazardous to least hazardous was made. This ranking is based simply upon the relative toxicity and chemical stability of the compounds. No judgment regarding the effectiveness of the container or shipping regulations was factored into the ranking. Plutonium (nitrate or oxide form) represents the most hazardous material with spent fuel and radioactive wastes being ranked second and third, respectively.

Nuclear Energy Demand and Nuclear Fuel Requirements

Nuclear Energy Demand

In the time period between 1975 and 1990, nuclear energy will be consumed by the electric utilities. Therefore, the demand for nuclear energy may be estimated from the total demand for electrical energy, the economic forces that determine the relative loading of conventional and nuclear generating stations and the availability of the nuclear stations.

The data accumulated on the domestic electrical energy demand for the years 1965 to 1970 can be closely represented by a constant growth rate of 7.18 percent per year.(V-5) Therefore, this linear growth rate was used to project the demand for electrical energy up to 1980, which is shown in Figure V-2. The projection after 1980 is more difficult. The markets which are now enjoying the most expansion (such as air conditioning) may be approaching saturation and the electrical industry growth may settle to a value near that of the gross national product--say about 4 percent per year. On the other hand some new market such as the electric car may develop and the growth rate may be greater than the 7.18 percent per year rate. For the purposes of this study we have used results from the updated EQUIPS study(V-1) in which a growth rate of 6.6 percent per year from 1980 to 1990 was assumed. This projection is not inconsistent with other previous projections.(V-6,V-7) The analysis in this study considers only domestic needs and the associated emissions. Estimates of nuclear demand and supply for the rest of the free world can be found in Reference V-7.

The segments of the demand for electricity for nonnuclear and nuclear power sources and the breakdown of nuclear into Light Water Reactor (LWR), High-Temperature Graphite Reactor (HTGR), and Liquid Metal Fast Breeder Reactor (LMFBR) generating stations was determined using the linear programming model of the U.S. power economy(V-2) developed for the USAEC. Results of the calculation also are plotted on Figure V-2 along with the actual generation using LWR's for 1968 to 1971. Demands by reactor type for four intervals are given in Table V-4.

TABLE V-4. ENERGY DEMAND

	Gigawatt Years of Energy Produced In			
	1975	1980	1985	1990
Nuclear				
Station Type				
LWR	50	100	170	260
HTGR	0.25	7	40	90
LMFBR		0.2	0.5	30
Total Nuclear	50.25	107.2	210.5	380
Total Nonnuclear	215	268	305	325
Total Energy Demand	265	375	515	705

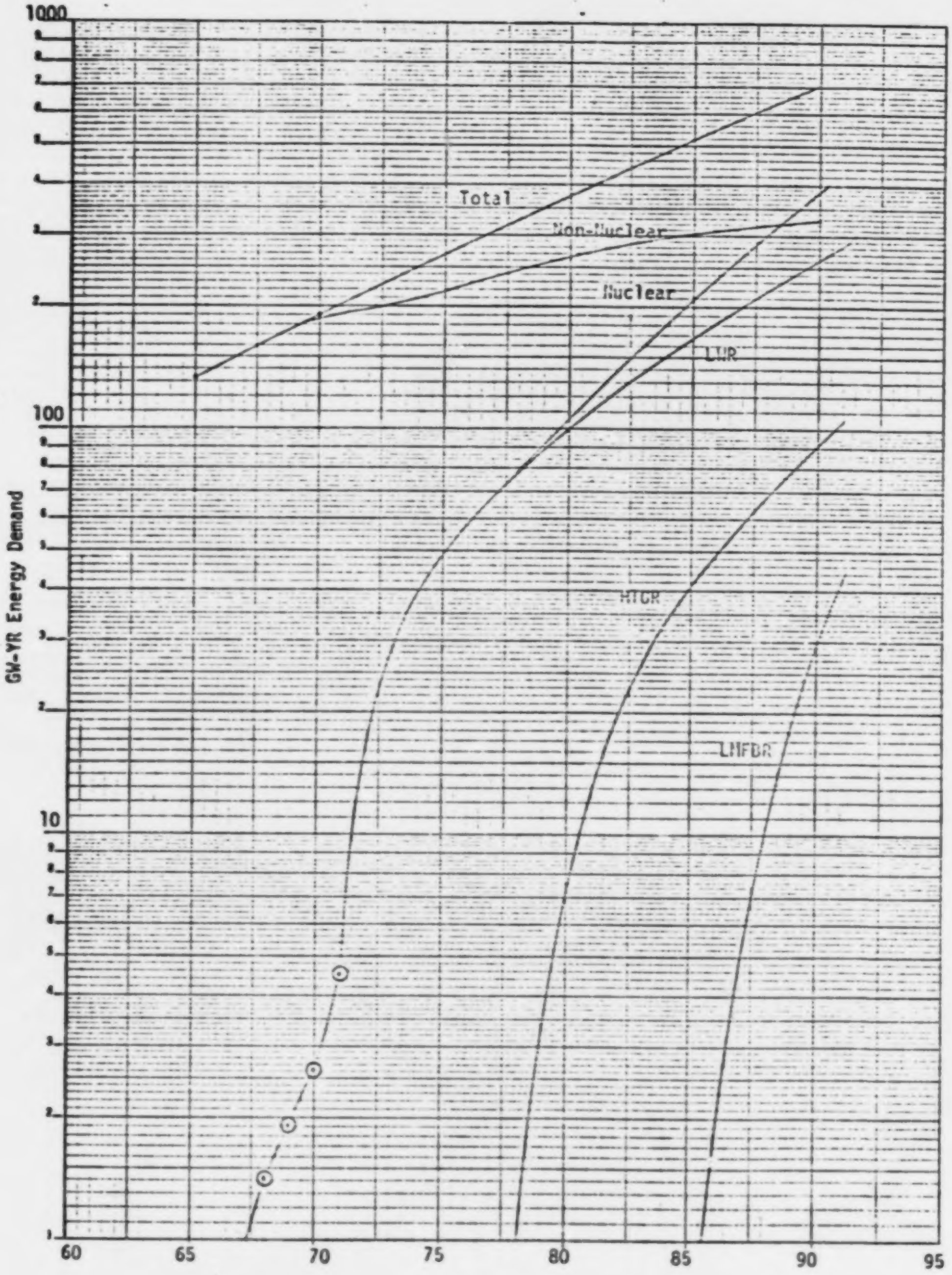


FIGURE V-2. ELECTRICAL ENERGY DEMAND (PRODUCTION)

As of August 15, 1972, the American Nuclear Society (ANS)$^{(V-8)}$ reported nuclear generating capacity built, under construction, or committed. They also estimated that an additional 21.7 GW (Gigawatts = 10^9 watts) would be committed in the near future. If these construction schedules are met, the installed capacity in 1975 and 1980 would be as follows:

ANS Estimates of Installed Nuclear Capacity in Gigawatts

Type	1975	1980
LWR	61	138
HTGR	0.33	2.24

Comparison of these data with Table V-4 indicates that it would be possible for the LWR's to meet the indicated demand, but that several HTGR's must be sold in the next year or so if the potential demand indicated by the model is to be met. It also is possible that construction schedules will not be met, so Table V-4 can be regarded as the upper estimate of the demand range to 1980 and probably can be regarded as the upper estimate to 1990 assuming no major new markets for electricity.

It should be noted that the nonnuclear share of the demand only increases slightly from 1985 to 1990 on Table V-4. This occurs even though the nonnuclear capacity increased substantially, since the nuclear plants are expected to be essentially base load plants and the nonnuclear plants will be phases out of base load operation and used to satisfy seasonal and daily peaks. It is expected that much of the new nonnuclear construction will be of the "mid-range" type designed to operate efficiently 12 hours a day, 5 days a week, in the 1980 to 1990 time period.

Nuclear Fuel Requirements

The linear programming model also produces a complete list of material flows. These flows reflect the appropriate lead or lag times for each step of the process to meet the projected electrical demand. For this reason, it is necessary to project the electrical demand well beyond the period of interest. In this case a growth rate of 5.6 percent per year after 1990 was used. This assumption has a strong effect on the flows in 1990. For example, since nuclear fuel may stay in a reactor for three or four years, the amount of fuel required and its enrichment depends on projecting up to four years in advance the energy that a reactor will produce. The U_3O_8 that will ultimately be a constituent of a particular batch of fuel must be purchased two years before that batch of fuel is charged to a reactor to provide time for the necessary process steps. Thus, a U_3O_8 requirement depends on estimating the electrical demands in the interval from two to six years in the future. The calculated material flows are given in Table V-5. The plant capacities listed in Table V-5 are plant nameplate values. The values of energy produced listed in Table V-4 are these values times the plant availability factor. The rest of the table lists the material flows from U_3O_8 and ThO_2 requirements to recovered plutonium after reprocessing.

TABLE V-5. CALCULATED MATERIAL FLOWS

Material		Requirements 1975	1980	1985	1990
Plant Capacity In GW[(a)]	- LWR	61	138	225	357
	- HTGR	.33	9.33	56	119
	- LMFBR	0	.3	.7	40
U_3O_8 Requirements in tons[(b)]	- LWR	20,000	31,500	49,000	73,800
	- HTGR	30	2,500	9,500	17,000
	- LMFBR				1,400
ThO_2 Requirements in tons	- HTGR	3	400	1,000	2,200
Separative Work In MT[(c)]	- LWR	15,200	24,500	28,900	42,600
	- HTGR	20	2,100	8,100	14,600
	- LMFBR				600
Fuel Fabrication in MT	- LWR	3,100	5,400	9,000	14,100
	- HTGR	4	270	800	1,800
	- LMFBR		3	7	1,600
Fuel Reprocessed in MT	- LWR	1,300	3,400	5,500	10,100
	- HTGR	(d)	(d)	(d)	820
	- LMFBR		3	7	540
Plutonium Recovered In MT		3	31	63	150

(a) GW meaning gigawatts or 10^9 watts.

(b) Short tons (2000 #).

(c) MT meaning metric tons.

(d) Commercial reprocessing to start in 1986.

Uranium Mining

Technology Summary

Uranium occurs throughout the world in both the lithosphere and in the oceans. Uranium mining operations involve extracting the crude ore from uranium mineral deposits and transporting the ore to the mill. Nearly all of the domestic ore deposits and known reserves occur in sedimentary formations of the Jurassic and Tertiary periods. About half of the deposits occur in the Colorado Plateau region, principally in the Ambrosia Lake district in northern New Mexico. The other half occur in sedimentary formations of the Jurassic and Tertiary periods. About half of the deposits occur in the Colorado Plateau region, principally in the Ambrosia Lake district in northern New Mexico. The other half occur principally in the Wyoming Basin district in central Wyoming. About 10 percent of the deposits occur in the Colorado Plateau region, principally in the Ambrosia Lake district in northern New Mexico. The other half occur principally in the Wyoming Basin district in central Wyoming. About 10 percent of the reserves are scattered throughout the other western states. Most of the uranium reserves are shallow; the median depth is 350 feet, and 90 percent are less than 1,000 feet. The average grade of ore is 0.2 percent U_3O_8, and the average deposit contains 3,000 tons U_3O_8.

Both underground and open pit methods are used. Underground mining is used for the small ore bodies near the surface and for large ore bodies over 400 feet deep. Open pit mining is used for large ore bodies less than 400 feet in depth. In 1969, the average underground mine produced 50 tons of U_3O_8 annually and employed 18 people. The average open pit mine produced 430 tons of U_3O_8 annually and employed 68 people.

Currently, 57 percent of the U_3O_8 is mined underground and 41 percent is open pit. The remaining 2 percent comes from other sources such as by-products of vanadium and thorium mining. In the future the USAEC stockpile could likewise contribute; a constant 2 percent from all other sources is projected in the future and is not considered in the uranium mining impact. However, data on the ore reserves (that which is recoverable at a cost under \$10/lb U_3O_8) indicate a trend, showing 56 percent of the reserves should be mined open pit and 44 percent underground because the known deposits favor open pit mining techniques. These data suggest that future uranium mining will be more oriented towards open pit mines. An estimated breakdown for each five-year interval from 1975 to 1990 is given in Table V-6. Using these fractions and the total U_3O_8 requirements, throughputs for each mining process for the years 1975, 1980, 1985, and 1990 can be obtained and these are given in Table V-7.

An effluent flowsheet for uranium mining is shown in Figure V-3. The process involves simply removing the ore from the ground and placing it in the vehicle used to transport it to the mill.

TABLE V-6. ESTIMATED DISTRIBUTION OF URANIUM EXTRACTION

Year	Percent Underground	 Open Pit	 Other
1970 Data	57	41	2
1975 Estimate	55	43	2
1980 Estimate	50	48	2
1985 Estimate	45	53	2
1990 Estimate	40	58	2

TABLE V-7. SUMMARY OF URANIUM MINING THROUGHPUTS

	1975	1980	1985	1990
U_3O_8 Requirements by Plant Type, tons				
LWR	20,000	31,500	49,000	73,800
HTGR	30	2,500	9,500	17,000
LMFBR				1,400
Total U_3O_8 Requirements, tons	20,030	34,000	58,500	92,200
Amount Underground Mined	11,017	17,000	26,325	36,880
Amount Open Pit Mined	8,614	16,320	31,005	53,476
Amount Other Processes	400	680	1,170	1,844

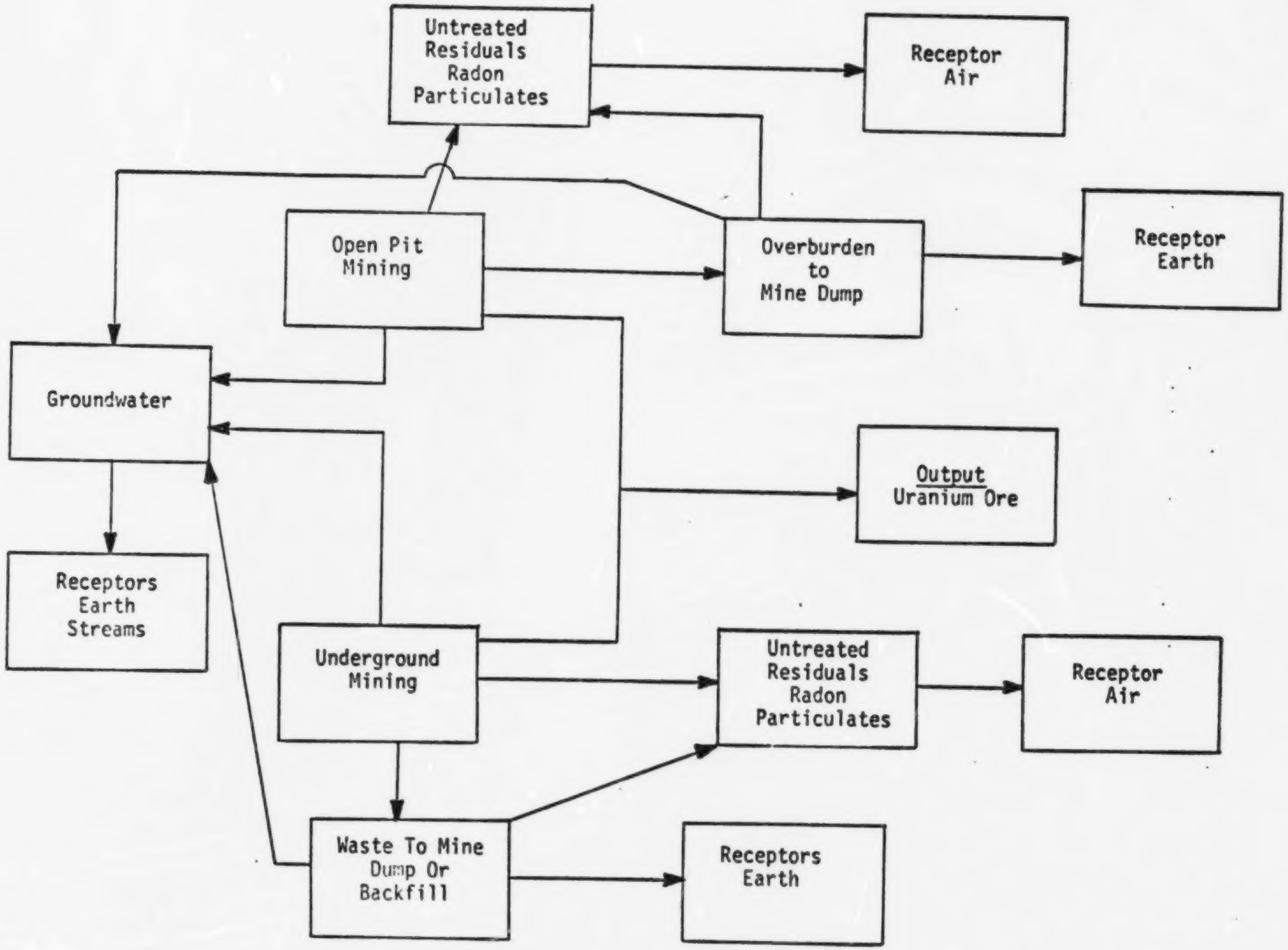

Untreated
Residuals
Radon
Particulates
Receptor
Air
Open Pit
Mining
Overburden
to
Mine Dump
Receptor
Earth
Groundwater
Output
Uranium Ore
Receptors
Earth
Streams
Underground
Mining
Untreated
Residuals
Radon
Particulates
Receptor
Air
Waste To Mine
Dump Or
Backfill
Receptors
Earth

FIGURE V-3. URANIUM MINING

Emissions

Environmental parameters would include land use, water usage and contamination, the usage of other resources in mining, construction of access roads and power lines, dumping of waste rock, and air pollution. The potential magnitude of each of these parameters is discussed in the following paragraphs.

Air. Surface air pollution is apparently no concern. The radon problem is confined to miners in underground mines, and atmospheric dilution is sufficient above ground.

Water. Potential water usage, withdrawal, and contamination during uranium mining are difficult to estimate. Some ore deposits are in active aquifiers so some additional leaching may occur when the deposit is disturbed. Other deposits are in impermeable strata so this affect would not be present, but some waste rock brought to the surface may contain a small amount of uranium and its daughters. This rock could weather and contaminate surface waters. No data were immediately available to quantify these affects.

Land. Most mines are located near mills, probably within ten miles. If half this distance is traveled on main arterials, then about five miles of access road would be required per mine. Power lines would be required at the mill site so that, at most, ten additional miles of power transmission line would be required per mine. Since mines tend to be clustered, these estimates would tend to be high.

Waste rock is very high in uranium open pit mining, running about 30 cubic yards per ton of ore. In underground mining, the waste rock would be much lower--one cubic yard or less per ton of ore.

Land requirements for underground mines would probably average less than ten acres of cleared area for the surface buildings and mine dump for each mine. The mine property and adjacent claims, however, would cover several thousand adjoining acres. The average open pit mine would require an estimated 400 acres for mining and stripping the overburden.

Summary of Emissions. Assuming (1) uranium mining practices follow the current reserve data, (2) a homogeneous linear production function of the first degree, and (3) an average mine life of 20 years, we can express the potential emissions in terms of tons of U_3O_8 consumed as shown in Table V-8. These data are combined with the U_3O_8 throughputs from underground and open pit mining (Table V-7), to give the summation of incremental emissions for the 5-year periods from 1975 to 1990. These are given in Table V-9 for each mining process and are added together (net columns) to give the total incremental emissions.

Land used in open pit mining could be partially reclaimed during the mining period by covering waste rock with topsoil and planting a cover crop. After the ore body is exhausted, the entire land area could be reclaimed by refilling and planting. In underground mines the waste rock could be partially disposed of by backfilling mined out stopes. The incremental impact of uranium mining operations on land usage is shown in Table V-10; it is assumed that the widths of land affected by transmission lines and access roads are 20 and 50 feet, respectively.

TABLE V-8. POTENTIAL ENVIRONMENTAL IMPACT OF URANIUM MINING
(Data expressed as quantity per ton U_3O_8)

Parameter	Underground Mining	Open Pit Mining
Surface Area Affected	0.01 acre	0.05 acre
Access Roads	0.005 mile	0.0006 mile
Transmission Lines	0.01 mile	0.001 mile
Waste Rock	450 cubic yards	14,000 cubic yards
Air:		
Particulates	No data available	No data available
Radon Gas	No data available	No data available
Water:		
Deposit Leaching	No data available	No data available
Waste Leaching	No data available	No data available

TABLE V-10. SUMMARY OF INCREMENTAL LAND USAGE FOR URANIUM MINING

	1975	1980	1985	1990
Transmistion Lines, acres (20 ft wide)	288	452	713	1090
Access Roads, acres (50 ft wide)	365	575	913	1316
Mine Surface Area, acres	540	986	1813	2674
Total Acres	1193	2013	3439	5080

It is assumed that mining operations have a negligible affect on the concentration of radioactive isotopes in water. However, if it is determined that there is an increase, the water could be collected and treated. In the case of ore deposits in an aquifier the treatment would

TABLE V-9. SUMMARY OF URANIUM MINING IMPACTS

	1975			1980			1985			1990		
Impact	U.M.†	O.P.M.††	Net	U.M.	O.P.M.	Net	U.M.	O.P.M.	Net	U.M.	O.P.M.	Net
Land												
- Surface area, acres affected	110	430	540	170	816	986	263	1550	1813	369	2674	3043
- Access roads, miles affected*	55	5.2	60.2	85	9.8	94.8	132	18.6	150.6	185	32.1	217.1
- Transmission lines, miles affected**	110	8.6	118.6	170	16.3	186.3	263	31.0	294	396	53.4	449.4
- Waste rock, cubic yards	4.96×10^6	120.6×10^6	125×10^6	7.7×10^6	228.5×10^6	236×10^6	11.8×10^6	434.1×10^6	446×10^6	16.6×10^6	748.7×10^6	765×10^6
Air												
- Particulates	No Data Available											
- Radon emission	No Data Available											
Water												
- Deposit leaching	No Data Available											
- Waste leaching	No Data Available											

† U.M. = Underground mine.

†† O.P.M. = Open pit mine.

* Width of roads not included.

** Width of transmission lines not included.

be applied to the effluent from the dewatering pumps. In the case of deposits in a dry area, any water that contacted the ore would first have to be collected and then treated.

Control Mechanism Costs

For underground mining operations, atmospheric dilution of radon gas and particulates is sufficient and does not constitute a problem in the atmosphere. For surface mines, except for rare inversions, radon gas does not constitute a problem. Even this occurs only at the bottom of the open pit mine. Dust from the mining operation can become a nuisance hazard when mining uranium ore in some formations. There are many effective and inexpensive ways of eliminating the dust problem. Thus, no additional costs associated with minimizing the environmental emission of uranium mining have been considered.

Uranium Milling

Technology Summary

Uranium milling operations involve the extraction of uranium from ores. Generally, milling facilities are separate from mining operations and a single mill normally processes the output of a number of mines. The uranium-bearing ore, as it is delivered to the mills, may have a uranium content of from 0.1 to 2 percent (expressed as U_3O_8) and generally averages about 0.20 percent. This uranium is present primarily as U^{238} (99.27 percent) and U^{235} (0.71 percent), both of which are radioactive parents of long chains of radioactive daughter products. The majority of the ores delivered to the mill contain the daughter elements in secular equilibrium; i.e., the daughters are being formed at the same rate at which they are decaying. Among these are the longer lived daughters radium-226, lead-210, polonium-210, and thorium-230, and the short-lived gas radon-222.

The crude ores delivered to the mill are crushed, ground, and leached with a suitable solvent, either a sulfuric acid solution or a sodium carbonate solution, depending on the chemical composition of the ore. The resulting solutions, containing the uranium and other soluble components of the ore, are first physically separated from the insoluble portion of the ore, or gangue, then purified by solvent extraction or ion exchange techniques, and finally concentrated by chemical precipitation and filtration. The uranium product, the yellow-colored filter cake, is washed and dried before being shipped to feed material centers as "yellowcake". The U_3O_8 requirements by recovery process for the years 1975, 1980, 1985, and 1990 are given in Table V-11.

TABLE V-11. SUMMARY OF URANIUM MILLING THROUGHPUTS

	1975	1980	1985	1990
U_3O_8 Recovered, tons	20,000	34,000	58,500	92,000
Acid Leach Process[a]	15,200	26,000	45,500	70,000
Carbonate Leach Process[a]	4,800	8,000	13,000	22,000
Average U_3O_8 Content of Ore, %	.2	.2	.2	.20
Average Processing Loss, %	5.2	5.2	5.2	5.2
Total Ore Processed, tons				
Acid Leach Process	8×10^6	14×10^5	24×10^6	37×10^6
Carbonate Leach Process	2.5×10^6	4×10^6	7×10^6	11×10^6

(a) No separate considerations were given for milling processes other than acid leaching and carbonate leaching, such as heap leaching, in situ leaching, or mine water treatment.

Emissions

Environmental parameters in uranium milling operations include land use, water use and contamination, and effluent releases to the air. A waste effluent flowsheet for uranium milling operations is given in Figure V-4. The estimated distribution of radioisotopes in the milling process for producing one kiloton of U_3O_8 is given in Table V-12. The contributions of U^{238}, Ra^{226}, Pb^{210}, Po^{210}, Th^{230}, and Rn^{222} are included in the estimated total release of radionuclides because of their relatively strict maximum permissible concentration limits in water, and their toxicity. While the composition of ore deposit varies widely, and will probably decrease in quality as the known deposits continue to be worked, for this study the available ore has been assumed to have an average U_3O_8 content of 0.20 percent. Assuming a 5.2 percent processing loss, and an average activity of the ore of 515 Ci of U^{238} per ton of ore, 5.27×10^5 tons of ore, containing 270 Cu of U^{238} and each of daughter elements of interest, have been assumed to be processed to recover one kiloton of U_3O_8.

Air. The short-lived gas radon, a decay product of radon, a decay product of radium, is probably released from the ore during the crushing and grinding steps and is routed by the mill ventilation control system to the gaseous effluent stack. Subsequent to the milling operations, radon continues to be formed in the tailings piles as the radium in the waste piles continues its normal decay. Air erosion of the tailings accumulations with the subsequent dispersal of the radioisotopes fixed in the gangue is minimized by leveling and covering the tailings pile with suitable earth and vegetation covers.

Water. The bulk of the radioisotopes, other than uranium, that are contained in the original ore remain in the gangue which is stored in

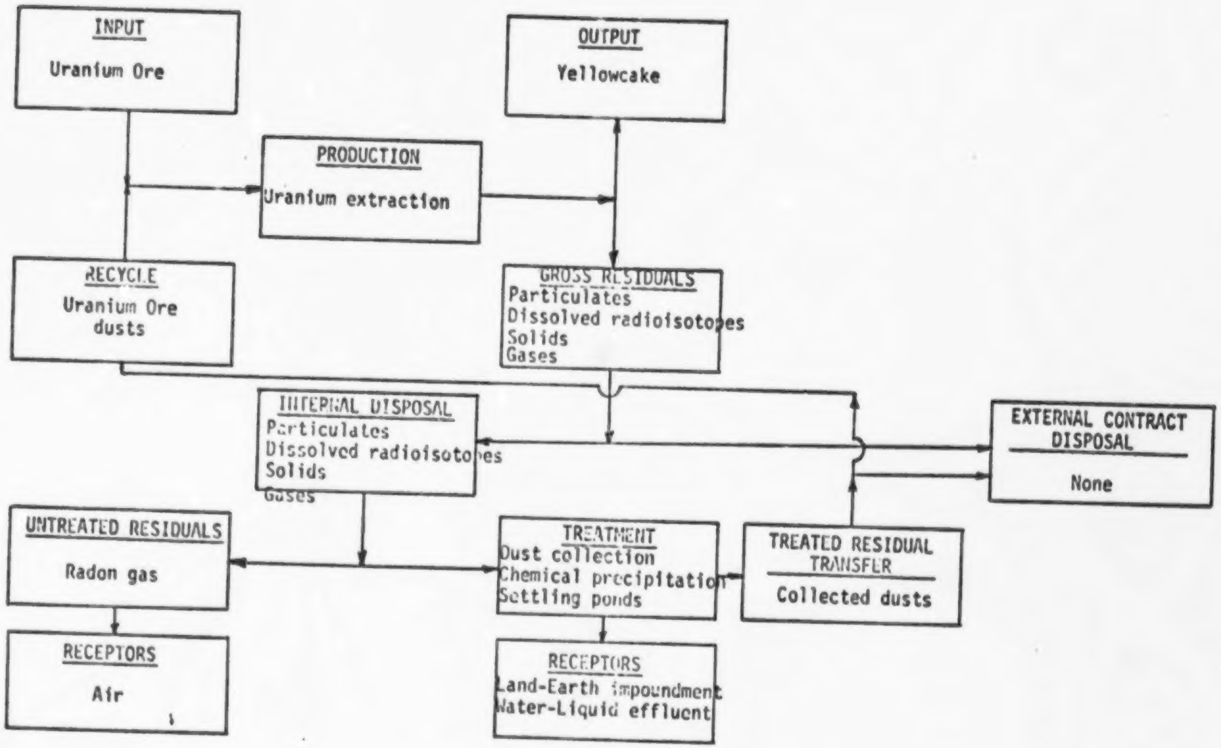

INPUT
Uranium Ore
PRODUCTION
Uranium extraction
OUTPUT
Yellowcake
RECYCLE
Uranium Ore dusts
GROSS RESIDUALS
Particulates
Dissolved radioisotopes
Solids
Gases
INTERNAL DISPOSAL
Particulates
Dissolved radioisotopes
Solids
Gases
EXTERNAL CONTRACT DISPOSAL
None
UNTREATED RESIDUALS
Radon gas
TREATMENT
Dust collection
Chemical precipitation
Settling ponds
TREATED RESIDUAL TRANSFER
Collected dusts
RECEPTORS
Air
RECEPTORS
Land-Earth impoundment
Water-Liquid effluent

FIGURE V-4. URANIUM MILLING

TABLE V-12. DISTRIBUTION OF RADIOISOTOPES IN URANIUM MILLING PROCESSES FOR PRODUCING ONE KILOTON OF U_3O_8 FOR ALL YEARS

	Acid Leach Process - Ci (gm)					
	U^{238}	Ra^{226}	Th^{230}	Pb^{210}	Po^{210}	Rn^{222}
Total in ore	270	270	270	270	270	270
Airborne material						270 (1.8×10^{-3})
Insolubles to tails	10 (33T)	265 (270)	135 (6600)	270 (3.5)	270 (.06)	
Solubles to process	260	5	135			
To yellowcake	256	1	5			
To liquid wastes	4 (13T)	4 (4)	130 (6300)			
To tails	1 (3.3T)	4 (4)	125 (6100)			
To effluent	3 (10T)	-	5 (250)			
Subsurface	3 (10T)	.00075	5 (250)			
Surface	.01 (.033T)	.00075	.005 (.25)			
Total to tails	11 (36)	269 (270)	260 (13000)	270 (3.5)	270 (.06)	
	Carbonate Leach Process - Ci (gm)					
Total in ore	270	270	270	270	270	270
Airborne material						270 (1.8×10^{-3})
Insolubles to tails	21 (70T)	265 (270)	270 (13000)	270 (3.5)	270 (.06)	
Solubles to process	249	5				
To yellowcake	246	5				
To liquid wastes	3 (10T)	0				
To tails	2.7 (9T)	0				
To effluent	.3 (1T)					
Total to tails	23.7 (7.8T)	265 (270)	270 (13000)	270 (3.5)	270 (.06)	

Note: Weights in parentheses are grams except for U^{238} where they are in tons.

tailings piles. The very small amounts of some radioisotopes that are leached from the ore along with the uranium are contained: (1) in the raffinate from the purification step, (2) in the barren solution from the uranium precipitation step, and (3) in the yellowcake product. The raffinate and barren solutions are chemically treated to precipitate the radioisotopes, and are discharged with the gangue to the tailings piles.

The aqueous solutions discharged to tailing or slime ponds are largely dissipated by evaporation or by seepage. Any outfall of such liquids into natural waters is monitored for its radioactive content. Restrictions on the release of radionuclides in liquid wastes necessitate either (1) recycle of clarified liquors with limitation of fresh water intake or just offset evaporation and seepage losses, or (2) treatment of effluents flowing off-site to precipitate and retain these nuclides. The latter expedient is now used in only three mills.

Tailings comprise an assortment of particle sizes ranging from slime to sand. They are mixed with water and pumped to the tailings ponds where the solids settle, and the water is recycled. The sands tend to segregate as the stream is delivered to the pond, leaving the liquid and slime to collect in low-lying areas. Abandoned tailings piles are stabilized against wind and water erosion.

Land. Land requirements for a uranium mill include surface area for production facilities and waste piles. Since we do not have estimates of these requirements readily available, we will neglect these factors in this study. There is an impact from earth impoundment of radioisotopes.

All solid and liquid wastes have been assumed to be discharged to tailings ponds for storage. The water content of the ponds at most mills will remain constant by either solar evaporation or seepage into the ground. Where seepage is possible, radionuclides will remain fixed in the soil beneath the pond and will not migrate with the water. A small percentage of mills will discharge excess pond waters to either natural waterways or deep well injection sites after meeting established standards for effluent waters.

Summary of Emissions. The uranium throughputs in the mill (Table V-11) are combined with the distribution of radioisotopes on the uranium milling processes (Table V-12) and summed to give the total radioisotope effluent discharged to air, land, and water receptors. These values are given in Table V-13 for the years 1975, 1980, 1985, and 1990.

Control Mechanisms and Costs

Processing of the ores results in airborne dust plus released radon gas during grinding operations and liquid wastes containing uranium during the dissolution of the ores and subsequent concentration of the uranium oxides. Dusts and radioactive gases created during grinding can be controlled by construction of appropriate ventilation hoods and by filtration of the effluent air. The radon gas passed through the air purification systems and is discharged with the atmosphere whereby it is dispersed. It would be possible to absorb the radon on activated carbon or to liquefy it, but such systems would be very expensive because of the large quantities of air accompanying the radon. Dusts removed in the ventilation system could be sent to the dissolution equipment and would not create a separate disposal problem.

TABLE V-13. SUMMARY OF URANIUM MILLING EMISSIONS

	Radioisotope Discharge to Receptors (Annual)			
	Total Curies of U^{238}, Rn^{222}, Ra^{226}, Th^{230}, Pb^{210}, Po^{210}			
	1975	1980	1985	1990
Acid Leach Process:				
Air	4,000(a)	7,000(a)	12,000	19,000(a)
Land	16,000	30,000	49,000	77,000
Water	0.2	0.4	0.7	1.1
Carbonate Leach Process:				
Air	1,000(a)	2,000(a)	4,000	6,000(a)
Land	5,000	8,000	16,000	24,000
Water	1	2	4	7

(a) The tabulated values do not include the continued releases of radon from the tailings piles as the radon continues to be formed from the normal decay of the radium contained in the tailings.

The liquid and solid wastes resulting from the dissolution and uranium oxide concentration are sent as described above, to the tailings ponds. The control mechanism consists of being certain that the tailings ponds do not overflow into natural water bodies and that any seepage out of the ponds has a low enough radioisotope concentration when it enters the groundwater or nearby water bodies.

The land used for tailings ponds generally is being reclaimed after the ponds are full by covering the wastes with enough clean earth to prevent a significant release of radon gas to the atmosphere. The cover is also designed such that water erosion will not wash the tailings out of the ponds.

The costs associated with these control methods have not been estimated because the basic information necessary for making the estimates is not available.

Thorium Mining and Milling

Technology Summary

The past and current demands for thorium have been small and have been almost entirely for nonenergy needs. However, increased use of thorium in high-temperature gas reactors is expected in the near future and could result in a factor of twenty or more increase in the milling and refining of thorium ores by the year 1990.

Aside from a brief period of stockpiling by the AEC prior to 1962, the production of thorium has averaged about 110 tons (expressed as thorium oxide, ThO_2) per year. The principal uses have been for the manufacture of incandescent gas mantles and magnesium alloy additives. Assuming a modest growth rate of about 3 percent per year for these nonenergy uses of thorium, an annual requirement of about 200 tons can be foreseen by the year 1990. However, based upon the forecast of commercial development of thorium fueled power reactors, the annual domestic requirements for reactor grade thorium oxide alone has been estimated at approximately 2000 tons by the year 1990.

Thorium Mining. Historically, most thorium has been recovered as a by-product in the chemical processing of monazite beach sands for their rare earth oxide (REO) content. Monazite is a naturally occurring mineral, essentially a phosphate of the rare earths, cerium and lanthanum, in which thorium and the yttrium earths substitute for cerium. In addition there are usually present small to moderate amounts of uranium, iron, aluminum, calcium, magnesium, silicon, titanium, and zirconium. Unlike many other rocks and minerals, monazite is not soluble in water, and so is not destroyed during erosion processes. Instead, the pulverized monazite accumulates, along with other erosion resistant minerals, as sand on river bottoms and ocean beaches. While natural separations processes have created some sand deposits that have been almost pure monazite, the domestic sources are mixtures of many erosion resistant minerals. These deposits are generally mined by placer mining methods, and separated into relatively pure mineral fractions by froth flotation, tabling, gravity separation, magnetic separation, or other ore beneficiation techniques. These preliminary separations are generally accomplished at the mine site with the tailings being returned to their natural environment. Since there are no crushing or grinding operations and no chemical treatments during this separation, there is no increase in radioactive release to the environment. With proper controls there is no long-term impact on air, water, or land.

Thorium Milling. The upgraded ore is chemically processed to effect further separation and purification of the desired elements. Historically the initial treatment has been to grind the ore and then solubilize it, either with a hot concentrated sulfuric acid treatment or a hot concentrated sodium hydroxide-hydrochloric acid treatment. Careful stepwise neutralization and filtration of the solubilized ore then results in the removal of the insoluble gangue materials and the fractional precipitation of relatively pure fractions of thorium, uranium, and rare earth compounds. The crude thorium fraction is then redissolved and purified by fractional precipitation, fractional crystallization or solvent extraction.

However, for the continuous, large-scale production of thorium of reactor-grade quality, solvent extraction processes utilizing solubilized ore solutions directly are highly attractive. Patterned after uranium solvent extraction processes, several thorium solvent extraction processes have been investigated, some through the pilot-plant stage.

The refining of the concentrated monazite ore will probably utilize a hot-caustic ore digestion process and after removal of the resultant trisodium phosphate solution, the metal hydroxides in the filter cake will be dissolved in nitric acid. A multiple step, solvent extraction process will then be used to separate the thorium, uranium, and rare earth fractions from one another and from any undissolved gangue materials. It has been assumed that 100 percent of the thorium, uranium, and daughter elements will be solubilized by the digestion process. It has been assumed that about 3 percent of the uranium will be lost to the filtrate when the hydrous oxides are filtered from the trisodium phosphate solution. It also has been assumed that approximately 0.1 percent of the thorium and uranium will be lost to the solvent extraction waste solution in the separation process. Finally, it has been assumed that 100 percent of the radium will appear in the solvent extraction waste solution.

The uranium nitrate fraction will enter the uranium fuel cycle for eventual fabrication into reactor fuel elements. This source of uranium is only about 0.1 percent of the total uranium processed for reactor use and its contribution is included in the Uranium Milling section of this report.

It has been assumed that the thorium nitrate fraction from the solvent extraction process will be converted to the oxide in the milling plant and shipped to the fuel fabricator as the oxide. It has been assumed that no radioactive wastes will be generated by this conversion.

The trisodium phosphate fraction, containing approximately 100 ppm uranium will be utilized as a crude TSP source without further uranium separation.

The requirements of thorium oxide (ThO_2) for the years of interest are shown in Table V-14. While the composition of ore deposits varies widely, depending on the location of the deposit, for this study it has been assumed that domestic deposits will be utilized and concentrated at the mine site to about 90 percent pure monazite. The average composition of the ore concentrate has been assumed to be:

	Percent
Thorium (as ThO_2)	4
Uranium (as UO_2)	0.2
Gangue	10

The estimated distribution of radioisotopes in the milling process for producing one ton of ThO_2 is given in Table V-15. In the decay of the parent thorium-232 to stable lead-208, 10 other radioisotopes are formed. Because of the extremely short half-lives of most of these radioisotopes only the parent thorium-232, radium-228, and thorium-228 have been considered for their environmental emission. Then, because of the relatively small quantities of uranium associated with natural thorium, only the parent uranium-238, and the very hazardous daughter, radium-226, have been considered of the radioisotopes formed in the normal decay of uranium-238. The daughters have been assumed to be in secular equilibrium with the parents. The half-lives and specific activities of these isotopes have been assumed as follows:

Isotope	1/2 Life, yr	Ci/lb	g/Ci
Th^{232}	1.39×10^{10}	5.03×10^{-5}	9.01×10^{6}
Th^{228}	1.91		1.22×10^{-3}
Ra^{228}	5.7		3.63×10^{-3}
U^{238}	4.51×10^{9}	1.51×10^{-4}	3.00×10^{6}
Ra^{226}	1.62×10^{3}		1.02

TABLE V-14. SUMMARY OF ThO_2 MILLING THROUGHPUTS

	1975	1980	1985	1990
Nonenergy Uses	130	150	170	200
Reactor Use	0	270	1000	2100
Total	130	420	1170	2300

Emissions

Environmental parameters in thorium milling operations include land use, water use and contamination, and effluent releases to the air. For the purposes of this study, it is assumed that the mining of thorium does not result in any environmental impact. The process waste flowsheet for thorium milling operations is given in Figure V-5.

Air. Radon gas is released during processing, presumably at the hot-caustic digestion step; however, the equipment is large and the gas volume small providing time for most of the gas to decay since the half

TABLE V-15. DISTRIBUTION OF RADIOISOTOPES IN THE PRODUCTION OF ONE TON OF ThO_2

Item	Ore Concentrate	ThO_2 Product	Tri-Sodium Phosphate Product	UO_2 Product	Solvent Extraction Waste
Gangue - lbs	5000				
ThO_2 - lbs	2002	2000			2
Th - lbs	1759	1758			1.76
Th^{232} - Ci	8.85×10^{-2}				8.85×10^{-5}
- gm	8.0×10^{5}				8.0×10^{2}
Th^{228} - Ci	8.85×10^{-2}				8.85×10^{-5}
- gm	1.1×10^{-4}				1.1×10^{-7}
Ra^{228} - Ci	8.85×10^{-2}				8.85×10^{-2}
- gm	3.2×10^{-4}				3.2×10^{-4}
UO_2 - lb	100		3	97	0.1
U - lb	88		2.64	85.5	.088
U^{238} - Ci	1.33×10^{-2}		3.99×10^{-4}	1.29×10^{-2}	1.33×10^{-5}
- gm	4.0×10^{4}		1.2×10^{3}	3.9×10^{4}	4.0×10^{1}
Ra^{226} - Ci	1.33×10^{-2}				1.33×10^{-2}
- gm	1.4×10^{-2}				1.4×10^{-2}

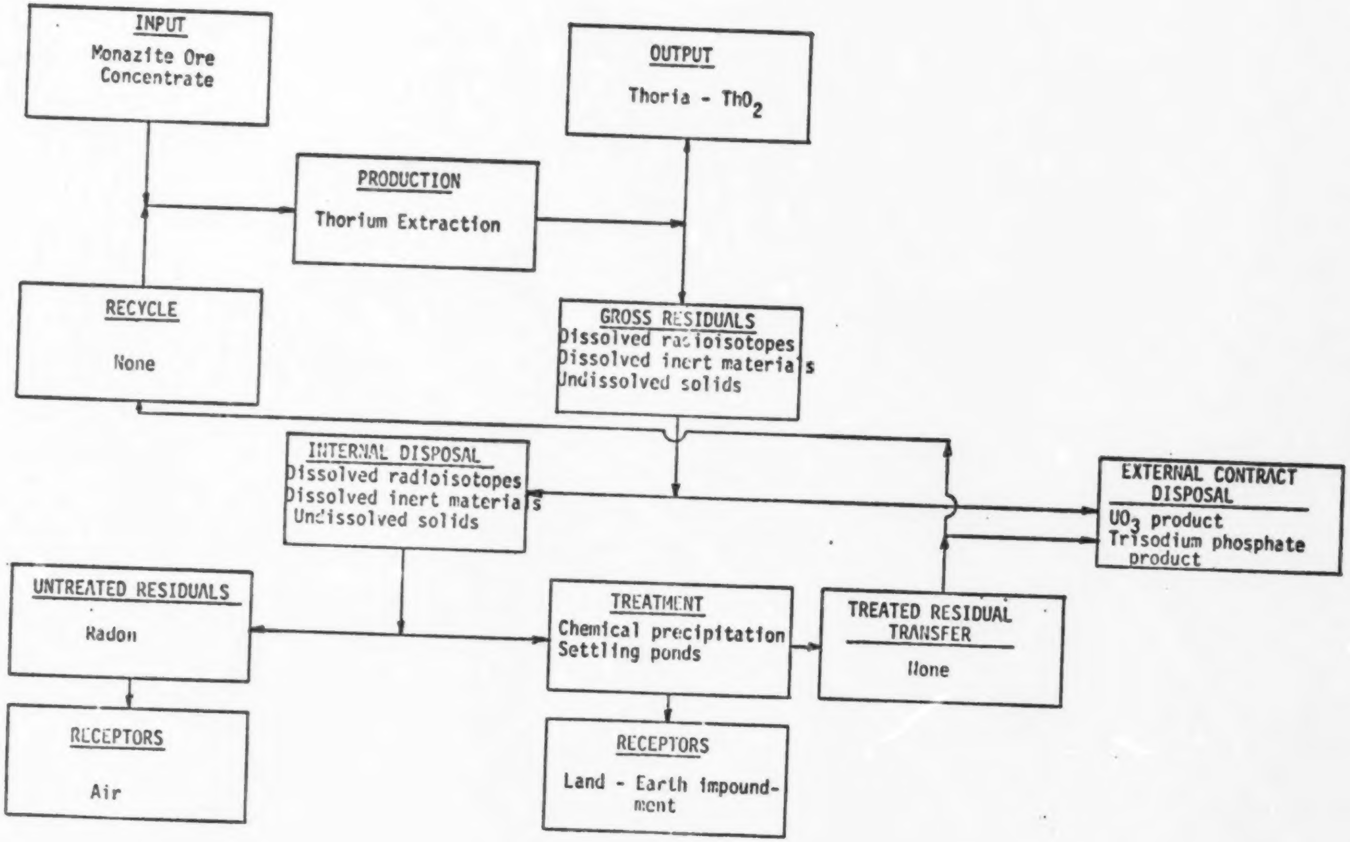

INPUT
Monazite Ore Concentrate
PRODUCTION
Thorium Extraction
OUTPUT
Thoria - ThO2
RECYCLE
None
GROSS RESIDUALS
Dissolved radioisotopes
Dissolved inert materials
Undissolved solids
INTERNAL DISPOSAL
Dissolved radioisotopes
Dissolved inert materials
Undissolved solids
EXTERNAL CONTRACT DISPOSAL
UO3 product
Trisodium phosphate product
UNTREATED RESIDUALS
Radon
TREATMENT
Chemical precipitation
Settling ponds
TREATED RESIDUAL TRANSFER
None
RECEPTORS
Air
RECEPTORS
Land - Earth impoundment

FIGURE V-5. THORIUM MILLING

life is only 56 seconds. Any residual is vented. Little or no particulates are expected.

Water. All liquid effluents are clarified by chemical precipitation and impounding in settling ponds. Any water released would be analyzed for chemical and radioactive content.

Land. The land area required for collection of solid wastes and settling ponds has not been estimated. This land area is the receptor for essentially all of the residual radioactivity.

Summary of Emissions. The thorium throughputs in the mill (Table V-14) are combined with the distribution of radioisotopes in the production of one ton of ThO_2 (Table V-15) and summed to give the total curies discharge to air, land, and water receptors. These values are given in Table V-16 for the years 1975, 1980, 1985, and 1990.

TABLE V-16. SUMMARY OF THORIUM MILLING EMISSIONS

	Radioisotope Discharge to Receptors			
	Total Curies of Th^{232}, Th^{228}, Ra^{228}, U^{238}, and Ra^{226}			
	1975	1980	1985	1990
Air	0(a)	0	0(a)	0(a)
Land	13	42	120	230
Water	0	0	0	0

(a) The actual distribution of the short-lived gas $radon^{220}$ throughout the milling industry is not known, particularly since the ore is mined in a pulverized state and is mechanically concentrated at the mine site prior to chemical milling procedures. Its contribution to the air receptor is not included in this study.

Control Mechanisms and Costs

Air. In the event better control is required the process vents may be placed under slight vacuum to preclude direct leakage to the air. One-thousand-fold reduction in radon activity could be obtained in a vent system with sufficient volume to provide a 10-minute hold-up. Costs for this increased control have not been estimated.

Water. All seepage and outflow should be monitored for radioactivity, soluble chemicals, and solids. Fresh water input should be controlled such that it is offset by evaporation and seepage.

Land. The land area which is to receive the waste and settling ponds should be stripped of top soil and seeded if required and monitoring wells provided. Precautions against erosion are required during use. When a given area has received the scheduled quantity of waste it should be re-covered with top soil and planted with a cover crop. Costs have not been estimated.

Uranium Conversion

Technology Summary

Crude natural uranium ore concentrates, yellowcake, are converted to uranium hexafluoride for purification to reactor-grade quality and as a feed material for the gaseous diffusion enrichment of the U^{235}-U^{238} ratio. Two commercial facilities owned by Allied Chemical and Kerr-McGee exist for the conversion of natural uranium ore concentrates. In the Allied Chemical process the ore concentrates are processed directly, after being pelletized to produce a feed material suitable for subsequent fluid-bed reactor systems. The concentrate is reduced with hydrogen to crude UO_2, and is followed by hydrofluorination with anhydrous HF to produce UF_4. In these two steps, a major portion of the impurities present in the original concentrate as volatile compounds (such as NH_3, H_2O, CO_2, etc.) or which form volatile compounds (such as S, Si, Mo, U, etc.) are eliminated in the off-gases. The crude UF_4 is then converted to UF_6 with elemental F_2. In this step, a major portion of the impurities forming nonvolatile compounds (such as Fe, Na, Cu, Mg, etc.) are rejected as solid ash. The small amount of remaining impurities vaporized and entrained with the UF_6, are removed by fractional distillation in both high- and low-boiling fractions. These fractions and minor amounts of scrap materials are treated for uranium recovery in a small auxiliary scrap-recovery system with a wet chemistry technique. Certain radioisotopes tend to build up in the fluid-bed heat exchange materials and necessitate the periodic replacement of a portion of this inert material. Ash wastes from the scrap recovery system and contaminated inert heat exchange materials are drummed and stored for eventual disposal. Off-gas scrubbers discharge effluents directly to waterways in accord with applicable radiation protection standards.

The Kerr-McGee process is somewhat similar, except the crude yellowcake is first purified by a solvent extraction process with the resulting uranyl nitrate solution being calcined directly to UO_2. Hydrofluorination and fluorination steps are similar but the fractional distillation step is not required. Raffinate from the solvent extraction purification is impounded in limestone-lined earthen ponds. Evaporation from the ponds approximately equals rainfall, and pond levels are maintained by seepage into the surrounding ground. Test well monitoring indicates that the radioisotopes impounded are relatively immobile. Off-gas scrubber solutions are discharged through limestone beds to waterways.

Assuming that the uranium conversion will be split evenly between the

Allied Chemical process and the Kerr-McGee process, then the uranium conversion requirements are as shown in Table V-17.

TABLE V-17. SUMMARY OF URANIUM CONVERSION THROUGHPUTS

	1975	1980	1985	1990
Yellowcake, tons U_3O_8	20,000	34,000	58,500	92,000
Recovered, tons U	17,000	29,000	50,000	78,000

Emissions

Environmental parameters in uranium conversion operations include land use, water use and contamination, and effluent releases to the air. A waste effluent flowsheet for uranium conversion operations is shown in Figure V-6. The estimated distribution of radioisotopes in converting U_3O_8 to one kiloton of uranium is given in Table V-18.

TABLE V-18. DISTRIBUTION OF RADIOISOTOPES IN THE CONVERSION OF ONE KILOTON OF URANIUM

	Curies		
	U^{238}	Ra^{226}	Th^{230}
Allied Chem. (1/2 kiloton U)			
Ash	0	.028	.8
Scrubber Solution	.012	--	--
Inert Materials	-----------	Unknown	-----------
Kerr-McGee (1/2 kiloton U)			
Raffinate	.2	.028	.8
Scrubber Solution	.012	--	--
Total (1 kiloton U)			
Liquid Materials	.224	.028	.8
To land receptor	.2	.028	.8
To water receptor	.024	--	--
Solid Materials	0	.028	.8
Inert	----------	Unknown	-----------

Water. In the Kerr-McGee process yellowcake impurities are removed in a solvent extraction step and the raffinate is impounded in limestone-lined, open ponds for permanent storage. Rainfall approximately equals evaporation from the ponds and a water balance is maintained by seepage

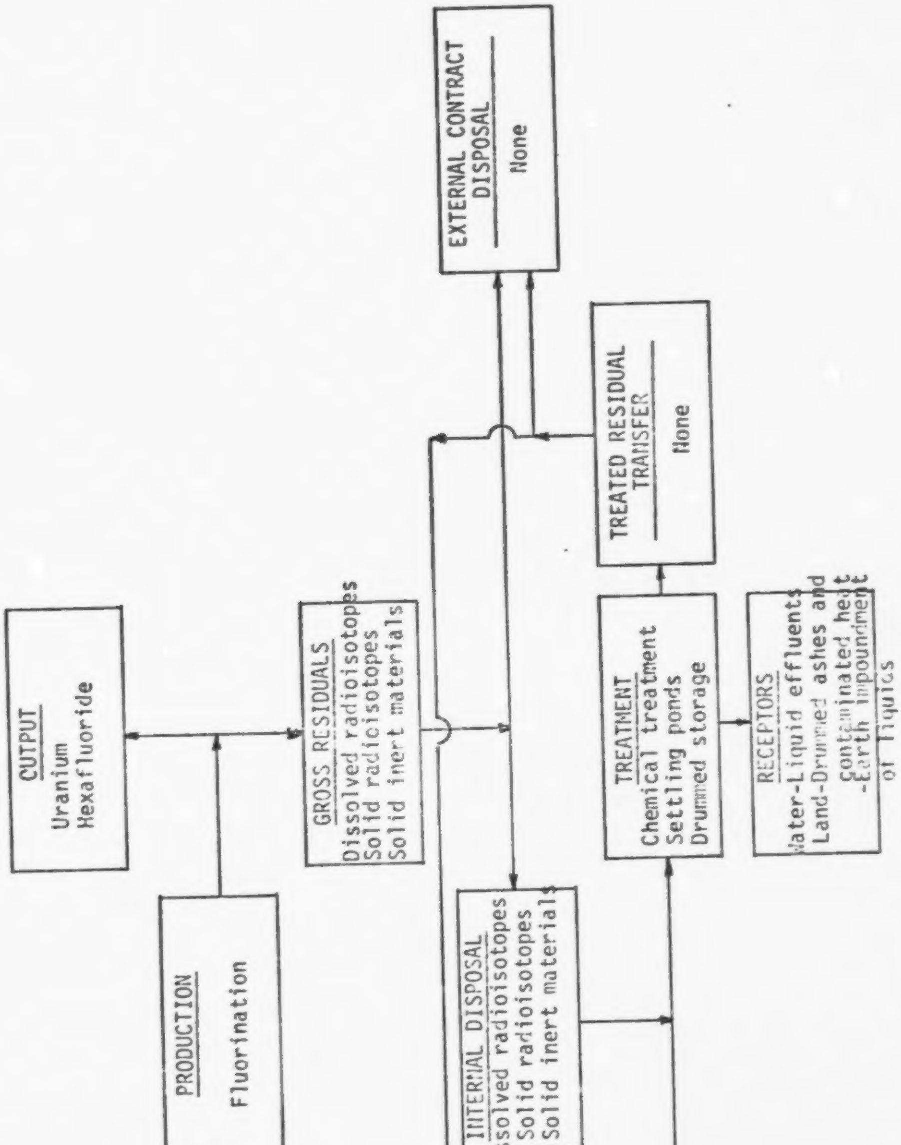

INPUT
Yellowcake
PRODUCTION
Fluorination
OUTPUT
Uranium
Hexafluoride
RECYCLE
GROSS RESIDUALS
Dissolved radioisotopes
Solid radioisotopes
Solid inert materials
INTERNAL DISPOSAL
Dissolved radioisotopes
Solid radioisotopes
Solid inert materials
EXTERNAL CONTRACT
DISPOSAL
None
TREATED RESIDUAL
TRANSFER
None
TREATMENT
Chemical treatment
Settling ponds
Drummed storage
RECEPTORS
Water-Liquid effluents
Land-Drummed ashes and
contaminated heat
-Earth impoundment
of liquids
UNTREATED RESIDUALS
None
RECEPTORS
None

FIGURE V-6. URANIUM CONVERSION

into the groundwater. Well monitoring indicates that the pond contents are relatively immobile.

Land. In the Allied process all of the uranium wastes, except the HF scrubber solution, are recycled (for product recovery) by a wet chemistry recovery method. Yellowcake impurities are removed in the recycle step. Some impurities collect in the fluid-bed heat exchange material, necessitating a periodic replacement of a portion of the bed. No data are available on the volume of "inert" heat exchange material replaced yearly. All inert wastes and yellowcake impurities are drummed and stored. HF scrubber solutions are discharged to waterways after neutralization.

Summary of Emissions. The uranium throughputs in Table V-17 are combined with the distribution of radioisotopes in conversion (Table V-18) and summed to yield the total discharge to air, land, and water receptors for the years 1975, 1980, 1985, and 1990. These values are given in Table V-19. The conversion of uranium recovered from irradiated fuels is not included in these estimates since the fluorination processes are not established at this time. It is most probable that these processes will be incorporated with fuel reprocessing plants and any wastes generated will probably be recycled through the reprocessing plant for product recovery.

TABLE V-19. SUMMARY OF URANIUM CONVERSION IMPACTS

	Radioisotope Discharge to Receptors			
	Total Curies of U^{238}, R^{226}, Th^{230}			
	1975	1980	1985	1990
Air	0	0	0	0
Land	31(a)	53(a)	92(a)	145(a)
Water	.4	.7	1.2	1.9

Control Mechanisms

Monitoring of wells adjacent to the waste ponds will reveal any excessive movement of the pond contents into the ground water. After a pond becomes full, it can be removed from service and covered with top soil and planted with a cover crop to prevent erosion. Costs have not been estimated for either the well installations or final entombment of the ponds.

Inert wastes and impurities from the Allied process stored in drums must be periodically inspected to assure that the drums have not failed. Scrubber solutions discharged to waterways must be monitored to assure that appropriate standards for such releases are not exceeded. Again, no costs have been estimated.

Uranium Enrichment

Technology Summary

Part of the uranium in the unirradiated power reactor fuel is enriched to assays above the natural assay in the USAEC gaseous diffusion plants (GDP's). The owner of the uranium to be enriched delivers it to the GDP's as UF_6 and receives back enriched UF_6 plus (if he wants it) UF_6 depleted in U^{235}.

At present the only commercial uranium enrichment facilities in the United States are the USAEC gaseous diffusion plants. These plants have ample capacity for current enriched fuel requirements and are expected to have ample capacity through 1980 if the planned capacity increases are completed. The required capacity increases after 1980 are assumed to be provided by construction of new private GDP's.

The standard operation of the GDP's for commercial uranium enrichment is expected to consist of (1) the customer delivers UF_6 to the GDP, (2) the GDP enriches the UF_6, and (3) the enriched UF_6 is delivered to the customer. It is assumed that the GDP feed plants for the production of UF_6 from other uranium compounds will not be used.

Current operation of the Oak Ridge GDP is assumed representative of all GDP operation for enrichment of power reactor fuels. There is no feed plant operating at Oak Ridge--only UF_6 is received as feed.

The only radioactive isotopes handled at the GDP's are uranium isotopes. In general, these appear as three waste streams: (1) leaking gases containing uranium, (2) uranium cleaned from the surfaces of equipment being maintained, and (3) miscellaneous solid wastes with uranium contamination.

All waste recovery systems are justified by recovery of the value of the uranium in the waste streams. The elimination of radiation releases is a side benefit since the recovery systems would have been installed whether or not the uranium was radioactive.

The throughputs for the uranium enrichment processes are tabulated in Table V-20 for the years 1975, 1980, 1985, and 1990. These throughputs are based upon a tails assay of 0.2 weight percent U^{235}. All uranium recovered during operation of the uranium recovery plant is sold as product to feed preparation plants. All uranium discharged from light water reactors is returned to the diffusion plants for reenrichment.

TABLE V-20. SUMMARY OF URANIUM ENRICHMENT THROUGHPUTS

	1975	1980	1985	1990
Tonnes[a] of Separative Work	15,200	26,600	37,000	57,800

(a) Tonnes = metric tons.

Emissions

Environmental parameters in uranium enrichment operations include land use, water use and contamination, and effluent releases to the air. A waste effluent flowsheet for uranium enrichment operations is shown in Figure V-7.

Air. Part of the uranium in the leaking gas streams is removed from the exhaust air stream by standard air purification equipment. The recovered uranium is stored or treated as necessary for eventual incorporation into the uranium fuel cycle. A very small part of the uranium passing through the GDP's leaks out during sampling or transfer operations, etc., and a small part adheres to the internal surfaces of the plant equipment. Appropriate exhaust gases are treated to recover the uranium content, and the uranium adhering to the equipment is recovered whenever the equipment has sufficient resale value to justify installation of all uranium recovery facilities solely on the basis of the recovered uranium value. All miscellaneous solid radioactive wastes are incinerated and the waste gases are treated before release to the atmosphere.

Diffusion plants consume large quantities of electricity for pumping the gases through the plant. All of this electricity is converted to heat, which is removed from the process by heat exchangers. The heat then is either transferred to the air in cooling towers or released in heated water to a nearby river. Insufficient information is readily available to permit estimate of the portion of the heat discharged to air or water. The amount of heat discharged as a result of production of enriched uranium for the power industry is as follows:

Year	Kwhr of Heat
1975	2.1×10^{10}
1980	3.6×10^{10}
1985	8.3×10^{10}
1990	1.3×10^{11}

Water. The primary effluent from the uranium recovery and decontamination facility is a liquid stream containing minor concentrations of uranium and other chemicals. This stream passes through an equalization basin and then is discharged to a river. Although some of the uranium may settle out in the basin, it is assumed that all uranium passes through the basin without settling.

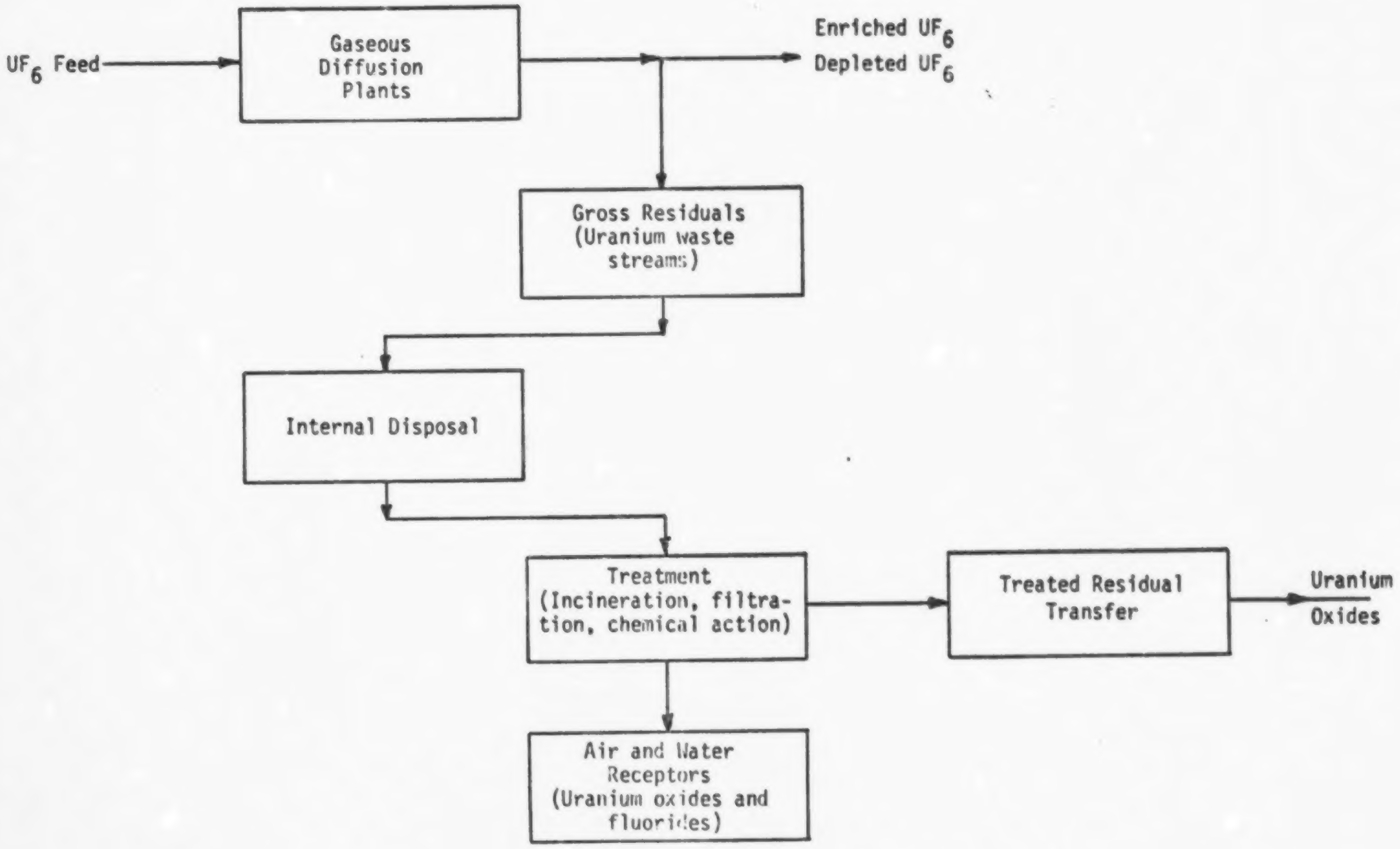

UF_6 Feed
Gaseous Diffusion Plants
Enriched UF_6
Depleted UF_6
Gross Residuals (Uranium waste streams)
Internal Disposal
Treatment (Incineration, filtration, chemical action)
Treated Residual Transfer
Uranium Oxides
Air and Water Receptors (Uranium oxides and fluorides)

FIGURE V-7. URANIUM ENRICHMENT

Land. The tails uranium is a stored product, part of which is sold to fuel fabricators for manufacture of LMFBR blanket fuels. The quantity of waste uranium is proportional to the units of separative work produced. No waste products are stored permanently on-site. The only land used is for the process facilities and the equalization basin.

Summary of Emissions. There are no waste treatment systems installed solely for reducing the quantity of radioactive materials released to the environment. All waste treatment systems would be installed anyway to reduce other chemical releases or to prevent loss of uranium values. All waste is treated.

The emissions to air, water, and land are summarized in Table V-21 for each isotope and totaled.

The forecast releases were obtained by assuming that the amount released is proportional to the units of separative work produced. Recent Oak Ridge GDP experience was used as the basis. This is a conservative assumption that probably results in an overestimate of the forecast releases by possibly as much as 200 percent. New GDP's built in the future will probably have improved seals and larger equipment capacities. The leakage rate per unit of product generally decreases as the equipment capacity increases. There are no releases to the land.

Control Mechanisms and Costs

Control of uranium releases to the air consists of assuring that the purification systems on the effluent ventilation system are operating properly. Similarly, control of uranium releases to water consist of measuring the concentration in the effluent streams to be certain that the liquid purification streams are operating properly. Since all of these purification systems are justified by the value of the recovered uranium, there is no extra cost for control mechanisms solely for reduction of the environmental emission of releases.

Fuel Fabrication

Technology Summary

Fuel fabrication may be divided into four broad groupings based on the contained nuclear material. The LWR's require two types, UO_2 using slightly enriched uranium, and mixed UO_2-PuO_2 using natural uranium and recovered plutonium. The amount of the latter depends upon plutonium availability. The LMFBR's use the same two types, UO_2 in the blankets and mixed oxides in the core. The other two types are used by the HTGR. Through 1985 the HTGR fuel will be a mixture of UO_2 enriched to 93 percent U^{235} and ThO_2. After the reprocessing plant starts up in 1986, some elements will contain recovered uranium which is predominantly U^{233}. The fuel fabrication requirements are presented in Table V-22.

TABLE V-21. SUMMARY OF URANIUM ENRICHMENT IMPACTS

	1975		1980		1985		1990	
	Amount (Kgs.)	Curies	Amount (Kgs.)	Curies	Amount (Kgs.)	Curies	Amount (Kgs.)	Curies
Gases & Airborne Material								
U234	.024	0.144	.044	0.269	.07	.428	.12	0.710
U235	2.8	0.006	5	0.011	7.2	.016	12	0.025
U236	.081	0.005	.026	0.016	.7	.044	1.5	0.096
U238	377	0.126	682	0.228	972	.325	1540	0.514
TOTAL	380	0.281	687	0.524	980	.813	1550	1.345
Liquids & Waterborne Material								
U234	.18	1.12	.34	2.10	.55	3.37	0.9	5.51
U235	21	0.047	39	0.086	56	.12	12	0.75
U236	.63	0.039	2	0.125	5.4	.34	1.5	0.096
U238	2938	0.982	5315	1.77	7640	2.55	11,960	3.99
TOTAL	2960	2.19	5357	4.08	7700	6.38	12,060	10.46

TABLE V-22. FUEL FABRICATION REQUIREMENTS

Element Type	Fabrication Requirements, metric tons of heavy metal 1975	1980	1985	1990
UO_2 - LWR	3,000	4,500	7,400	13,600
- LMFBR		2	4.7	1,070
Mixed Oxides of U + P - LWR	100	900	1,600	500
- LMFBR		1	2.3	530
Mixed Oxides of Th + U^{235}	3.5	270	800	1,000
Mixed Oxides of Th + U^{233}				800

UO_2 Fuel Fabrication

Current fabrication plants receive UF_6 and convert it to UO_2 by hydrolysis in water to form UO_2F_2 and H_2F_2 = HF. The UO_2F_2 is treated with ammonium hydroxide to form ammonium diuranate which is then calcined and reduced with hydrogen to form UO_2. The fluidized-bed process is under active development and may be expected to replace the ammonium diuranate in the near future, since capital and operating costs are lower and waste management is simplified. In this process the UF_6 is reacted directly with steam and hydrogen in a series of beds to yield UO_2 directly.

The UO_2 is pressed into pellets and sintered. The sintered pellets are sized to very close tolerances by centerless grinding. The pellets are loaded into the cladding tubes which are sealed by welding. The finished rods are cleaned to remove external contamination and assembled into fuel elements.

The waste process flowsheet is illustrated in Figure V-8. The nuclear fuel fabrication industry is unique in that the base value of the raw material exceeds by about a factor of two the value added in the fabrication process. The extremely high-quality standards of the industry result in a high rate of scrap generation. In most industries this scrap has a low economic value and a low pollution potential; as a result, it is usually considered waste. However, the scrap UO_2 has a high economic value and a significant pollution potential. Thus, it is impossible to allocate the amount of this recycle which can be attributed solely to pollution control.

The loss of material during the fabrication step, shown schematically in Figure V-8, is dependent on the flows through the various parts of the process. The flows through some parts, particularly following the UO_2 conversion step, are much greater because of the material recycled internally. Table V-23 shows the projected UO_2 internal recycle rates

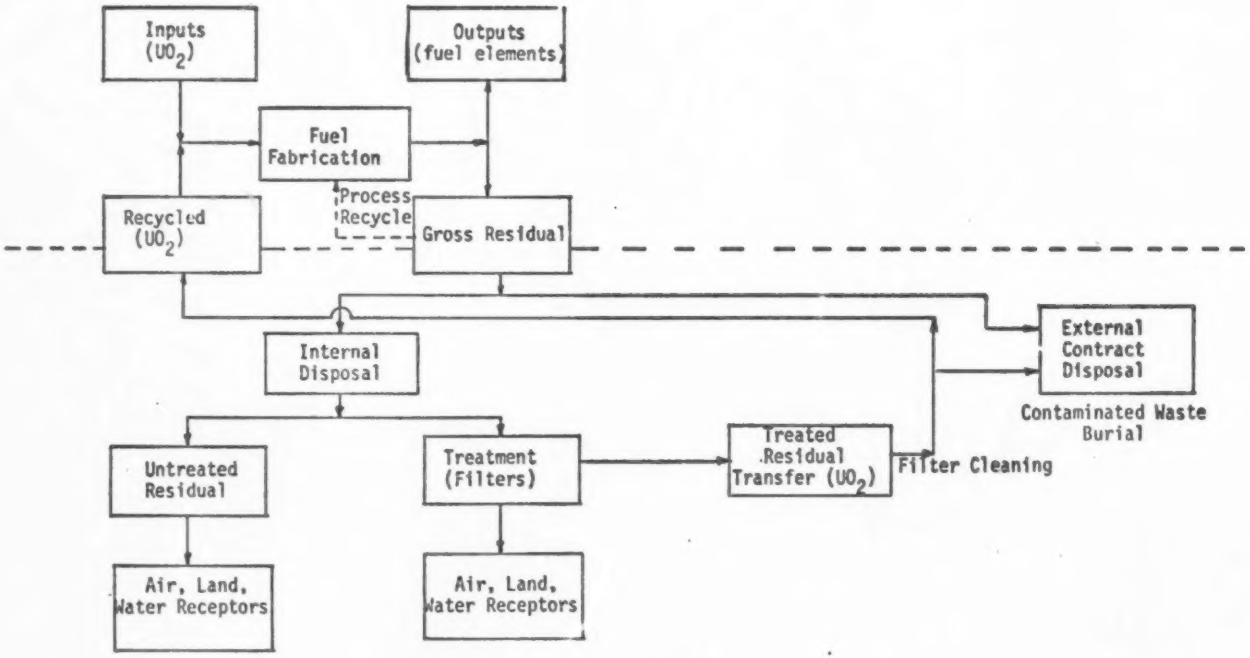

Inputs (UO_2)
Outputs (fuel elements)
Fuel Fabrication
Process Recycle
Recycled (UO_2)
Gross Residual
External Contract Disposal
Internal Disposal
Contaminated Waste Burial
Untreated Residual
Treatment (Filters)
Treated Residual Transfer (UO_2)
Filter Cleaning
Air, Land, Water Receptors
Air, Land, Water Receptors

FIGURE V-8. UO_2 FUEL FABRICATION

during the 1975 to 1990 time period.(V-10) These material recycle rates were used to adjust the releases to air and land. The losses to water are primarily from the UO_2 conversion process and were not increased by the values in Table V-23.

TABLE V-23. INTERNAL RECYCLE RATES

	Total Recycle, %
1975	17
1980	15
1985	15
1990	15

Emissions From UO_2 Fuel Fabrication. It should be pointed out that in many cases no historical data were available to estimate the emissions. In other cases, it was necessary to deduce releases from Special Nuclear Material (SNM) licenses and their amendments. The projected releases are even more speculative inasmuch as they usually project current technology and do not encompass possible improvements.

Air. The amount of UO_2 released to air is taken from a 1966 survey of the fuel fabrication industry.(V-11) This value is given in Table V-24.

TABLE V-24. AMOUNT OF UO_2 RELEASED IN FABRICATING ONE METRIC TON OF FUEL

	Air	Water	Land Burial
Grams of UO_2	1.1×10^{1}	2.5×10^{3}	2.0×10^{0}
Curies of UO_2	2×10^{-5}	4×10^{-3}	3×10^{-6}

Water. The amounts of UO_2 in the waste water are also taken from this 1966 survey.(V-11) This value is given in Table V-24.

Land. The amount of UO_2 in the waste to land burial was taken from the 1966 survey, with the exception of the volume of compacted dry waste. It was estimated that six cubic feet of dry waste are generated in processing one ton of fuel. This estimate is based upon more recent environmental report submittals by fuel fabricators. Waste burial was all assumed to go to a private external contractor. While this is not rigorously true (a small percentage of low level waste is buried by fabricators on their own property), the eventual disposal of this waste to the land is handled accurately by this assumption.

Summary of Emissions. For the purpose of converting the weight of UO_2 in the waste streams to curies, the following uranium assay was assumed:

Assumed Uranium Assay

	Wt %	Ci/gU
U^{234}	0.022	1.36×10^{-6}
U^{235}	2.56	5.48×10^{-8}
U^{238}	97.42	3.24×10^{-7}
Total	100.00	1.74×10^{-6}

The throughputs in Table V-22, increased to reflect the internal recycle as given in Table V-23, are combined with the release rates shown in Table V-24 to estimate releases to air, land, and water receptors. Using the assumed assay of uranium shown above, the activity values were derived and are given in Table V-25.

TABLE V-25. SUMMARY OF TOTAL RADIONUCLIDE RELEASE IN FABRICATING UO_2 FUEL

(in curies)

	Air	Land Burial[(a)]	Water
1975	0.56	0.0090	13.2
1980	0.86	0.0135	19.8
1985	1.41	0.0222	32.5
1990	2.79	0.0440	64.5

(a) This material sent to external contractor for controlled land burial

PuO_2 Recycle Fuel Fabrication

Plutonium oxide is always used as a mixture with uranium oxide in fuel elements. For LWR's the PuO_2 content will range from 2 percent to 5 percent while for LMFBR's it will be 10 to 25 percent. The UO_2 is prepared as described in the preceding section. The plutonium nitrate solution is converted to PuO_2 by precipitating plutonium oxalate and calcining. The oxides are mechanically mixed and the remaining steps are as described in the preceding section. The plutonium is assumed to have the following analysis:

Analysis of High Exposure Fuel From Yankee-Rowe Reactor
(31,400 MWD/MT Exposure)

Nuclide	Amount		Activity/Amount Ci/g Pu
Pu^{236}	0.047 (ppm)		0.025×10^{-3}
Pu^{238}	1.1 (wt%)		0.189
Pu^{239}	61.6		0.0378
Pu^{240}	20.9		0.0472
Pu^{241}	12.6		13.1
Pu^{242}	3.8		0.145×10^{-3}
Total	100.0	Avg.	1.68

Since the activity of natural uranium is less than 1 Ci/gU, it is safe to ignore the uranium isotopes in considering the activity of PuO_2-UO_2 fuel.

Thus, to get the activity released in terms of metric tons of fuel fabricated, it is required to specify the plutonium oxide content in the fuel. For a LWR, the fuel assembly is assumed to be 2.5 percent PuO_2 and 97.5 percent UO_2. For the LMFBR the plutonium fuel is assumed to be 15 percent PuO_2 and 85 percent UO_2. These enrichments were then used to calculate the PuO_2 throughput and subsequently the amounts of PuO_2 lost during fabrication.

Emissions From PuO_2 Recycle Fuel Fabrication. The waste system flow as shown in Figure V-9 is basically the same as that for UO_2 fuel fabrication. Again the conversion facilities from plutonium nitrate to the oxide were assumed to be included in the fabrication plants. The rationale for including "Process Recycle" is the same as in UO_2 fuel fabrication and will not be repeated here.

Air. The only data available for stack emissions from a plant producing mixed oxide fuel elements comes from the Hanford Plutonium Fabrication Laboratory. Emissions have routinely been below the detection limit of 2.2×10^{-8} Ci/week. If one scales these data up to the production level of 100 and 900 tons for 1975 and 1980, respectively, it would be concluded that the release to air for these years would be less than 5 Ci for 1975 and less than 47 Ci for 1980. For LMFBR fuel it was assumed that the releases would increase in direct proportion to the plutonium enrichment. Table V-26 shows the releases to air calculated per ton of LWR and LMFBR fuel. Plutonium enrichments of 2.5 and 15 percent were used for the LWR and LMFBR, respectively.

Summary of Emissions. The throughputs (Table V-22) increased to reflect internal recycle, are combined with the release rates (Table V-26) to give the total UO_2-PuO_2 released. Using the plutonium content and composition shown above, the total activity is estimated. These values are given in Table V-27.

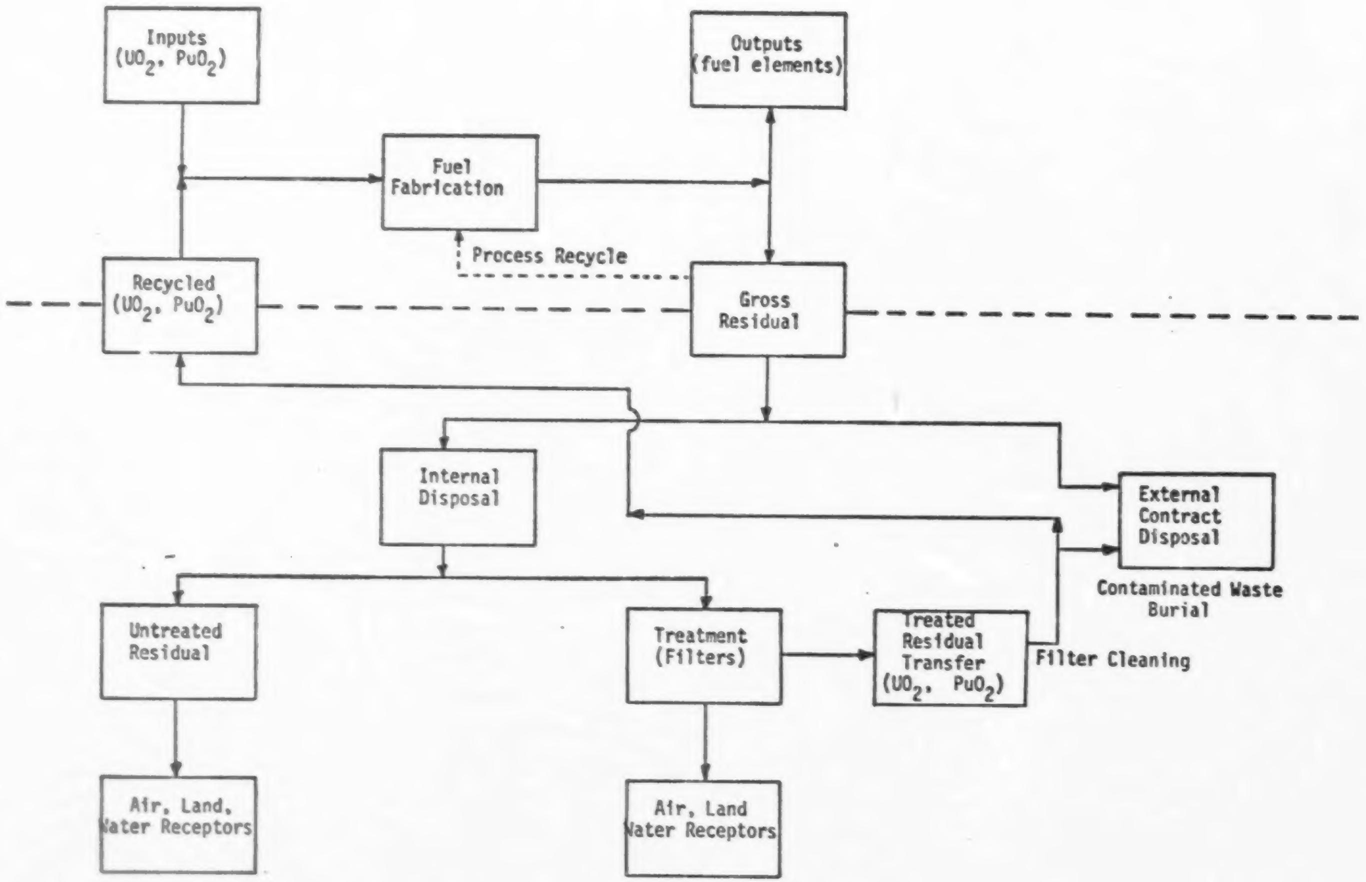

Inputs
(UO_2, PuO_2)
Outputs
(fuel elements)
Fuel
Fabrication
Process Recycle
Recycled
(UO_2, PuO_2)
Gross
Residual
Internal
Disposal
External
Contract
Disposal
Contaminated Waste
Burial
Untreated
Residual
Treatment
(Filters)
Treated
Residual
Transfer
(UO_2, PuO_2)
Filter Cleaning
Air, Land,
Water Receptors
Air, Land
Water Receptors

FIGURE V-9. MIXED OXIDE FUEL FABRICATION

TABLE V-26. RELEASE RATES IN FABRICATION OF UO_2-PuO_2 FUEL

(Based on 1MT of fuel fabricated in 1980)

	Air		Water		Land	
	LWR	LMFBR	LWR	LMFBR	LWR[(a)]	LMFBR
Grams	4×10^{-9}	3×10^{-7}	0	0	1.1×10^{2}	7.0×10^{2}
Curies	7×10^{-7}	4.2×10^{-6}	0	0	2×10^{2}	1.2×10^{3}

(a) Releases in 1980 are assumed to be 75 percent of the 1975 releases.

TABLE V-27. SUMMARY OF TOTAL RADIONUCLIDE RELEASE IN FABRICATING UO_2-PuO_2 FUEL

	Curies		
	Air	Land Burial(a)	Water
1975	70 Ci	$.2 \times 10^{5}$(b)	0
1980	630 Ci	1.8×10^{5}(b)	0
1985	1100 Ci	3.2×10^{5}(b)	0
1990	2600 Ci	7.4×10^{5}(b)	0

(a) This material sent to external contractor for controlled land burial.

(b) Based on present and forecasted practice. These may change appreciably if Pu wastes are required to be reduced to a homogeneous, nonoxidizable form before burial. This would increase the economic incentive for chemical recovery of Pu. Permanent disposal charges could have a similar effect.

Inspection of Table V-27 shows very low releases to air or water. The very low allowable limits for Pu release (6×10^{-14} Ci/ml for soluble Pu^{239} in air) require multiple air filtration with absolute filters. No planned releases are made to the water.

U-Th Fuel Fabrication

The commercial acceptance of the HTGR concept by the power industry means that the U-Th fuel cycle must be considered a significant source of wastes during the period of interest.

Present plans of Gulf General Atomic call for the construction of a large (at least 5 tons per day) integrated reprocessing and fuel fabrication plant. While the design details of this plant have not been announced, some conclusions can be made about the type of nuclear wastes which will be generated and the time when they may be expected to be released. The proposed startup date for the new plant is not until 1986. Even though irradiated HTGR fuel elements will be discharged in significant quantities starting in the middle of this decade, a "U-233 buyback" policy of the AEC allows the irradiated fuel to be stored, with a minimal economic penalty, until the plant is ready for operation. This means that the reprocessing-fabrication plant will probably come on stream later than would be the case without the buyback policy;' it likewise means that the plant will rapidly build up to full capacity operation once it does start.

The following shows both the annual and cumulative amounts of fuel expected to be discharged from HTGR's in the period of interest:

Fuel Discharged From HTGR's

	Year		
	1980	1985	1990
Fuel discharged in year (tonnes metal)	16	270	820
Cumulative discharged through year end (tonnes metal)	31	680	3575

If it is assumed that the plant starts up in 1986, it would probably not achieve full-scale operation until 1986. At 80 percent plant factor a 5 ton/day plant processes 1460 tonnes per year. Thus, it would be capable of processing the backlog in a year or two such that by 1990 it will be processing only current production. An overview of this transition was described by Lee and Jaye(V-12) at the 1971 winter meeting of the American Society of Mechanical Engineers. The current production in 1990 will require the production of about 800 tons of fuel containing recycled uranium and the remaining production of 1000 tons will contain only thorium and enriched uranium from the enrichment facility. The assumed composition of these two types of fuel is as follows:

Isotopic Composition of HTGR Fuels

Isotope	Wt % of Heavy Metal U-235-Th Fuel	Recycled Fuel
Th-232	93.95	91.84
U-232	3 ppb	11.3 ppm
U-233		2.26
U-234	.06	.87
U-235	5.54	4.64
U-236	.03	.05
U-238	.42	.34

Emissions From U-Th Fuel Fabrication. The waste flow diagram for HTGR fuel fabrication is shown in Figure V-10. The contributions of the various isotopes to the released activity will be a function of time after reprocessing due to the growth of the U-232 isotopes. For these calculations, it is assumed that the releases to the air and water occur a short time after reprocessing while those to land occur 6 months after reprocessing. These contributions are shown in Table V-28.

TABLE V-28. ISOTOPIC CONTRIBUTIONS TO HTGR FUEL RELEASES IN CURIES PER TON OF MATERIAL RELEASED

	Recycled Fuel		U-235-Th Fuel	
Isotope	Ci/T Released to Air and Water	Ci/T Released to Land	Ci/T Released to Air and Water	Ci/T Released to Land
Th-232	0.10	0.1	0.10	0.10
U-232 (and daughters)	242	527	.06	.14
U-233	251	251		
U-234	54	54	3.7	3.7
U-235	.10	.10	.12	.12
U-236	.03	.03	.02	.02
U-238	.001	.001	.001	.001
Total	547	832	4.0	4.1

The releases to air and water are assumed to be comparable to those expected in a PuO_2-UO_2 plant in the fabrication plant used through 1985. Due to the close coupled reprocessing-fabrication process in use after 1985, it is assumed that it will be economically sound to reprocess much of the fabrication scrap which would not be reprocessed in separate plants. It was arbitrarily assumed that the solid scrap buried would be one-half that in a comparable PuO_2-UO_2 plant. The plant design was assumed to include holdup tanks and monitoring such that water release would be nil.

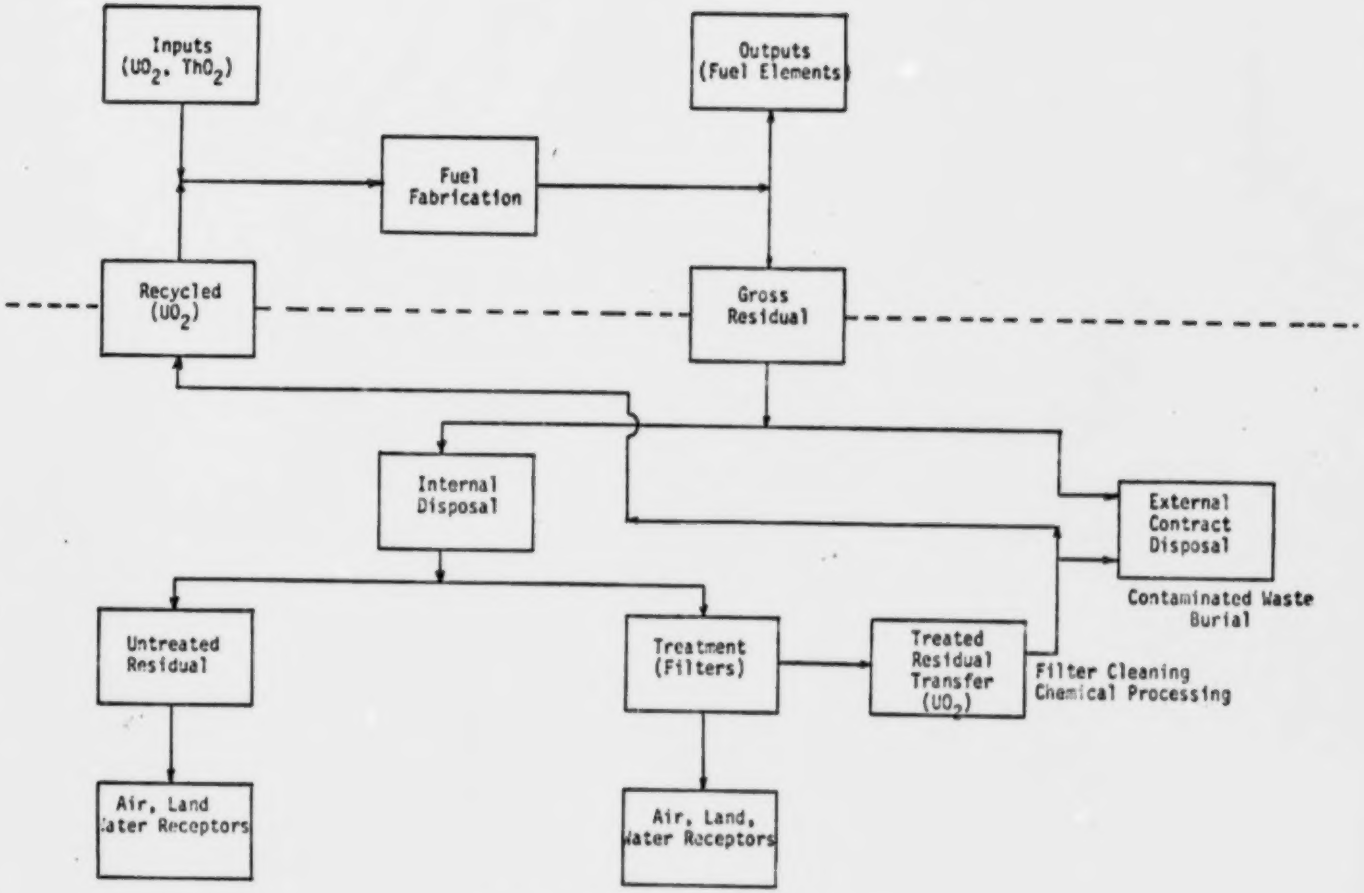

Inputs
(UO_2, ThO_2)
Fuel
Fabrication
Outputs
(Fuel Elements)
Recycled
(UO_2)
Gross
Residual
Internal
Disposal
External
Contract
Disposal
Contaminated Waste
Burial
Untreated
Residual
Treatment
(Filters)
Treated
Residual
Transfer
(UO_2)
Filter Cleaning
Chemical Processing
Air, Land
Water Receptors
Air, Land,
Water Receptors

FIGURE V-10. HTGR FUEL FABRICATION

Summary of Emissions. The throughputs for HTGR fuel (Table V-22) assuming the isotopic composition given above is combined with the release rates (Table V-26) and the activity of the released materials (Table V-28) to estimate the total activity released to air, water, and land receptors. These values are summarized in Table V-29.

TABLE V-29. SUMMARY OF TOTAL RADIONUCLIDE RELEASE FROM HTGR FUEL FABRICATION

Year	Air, Ci	Land,(a) Ci	Water, Ci
1975	1	.086	0
1980	1	5	0
1985	1	15	0
1990	1	1500	0

(a) This material sent to external contractor for controlled land burial.

Summary of Fuel Fabrication Releases. The summary of releases for the years of interest from all four types of fuel fabrication facilities is given in Table V-30.

TABLE V-30. SUMMARY OF RELEASES FROM FUEL FABRICATION PLANTS

Year	Air, Ci	Land,(a) Ci	Water, Ci
1975	.56	$.2 \times 10^6$	13.2
1980	.86	1.4×10^6	19.8
1985	1.41	2.6×10^6	32.5
1990	2.79	6.2×10^6	64.5

(a) This material sent to external contractor for controlled land burial.

Control Mechanisms and Costs

Air. Many of the process steps in a fabrication process involve handling of dry materials and in some steps substantial amounts of dust are formed. If the material is very hazardous or if the step produces more than a nominal amount of dust, the step is carried out in a hood. The hood filters are normally small and can be changed easily. They serve the dual purpose of permitting easy reclamation of lost material and protecting the large absolute filters (which are difficult to change) used to provide the necessary cleanup when working with very hazardous materials. All building air is filtered and the hood filter effluent is discharged to the suction side of the building air filters. Thus, all air is filtered at least once and the air from problem areas is filtered two or three times. Building entrances and exits may be provided with air locks and the building air pressure may be continuously recorded to insure that a vacuum is always maintained. Discharge air may be sampled with high velocity samplers to detect any leakage or bypassing of the filters.

Water. Process water requirements in a fabrication plant are nominal so all water is collected, analyzed, and treated if necessary before release.

Land. Solid contaminated waste is compacted if necessary and packaged to minimize leakage and normally sent to a licensed waste disposal site. Controls would consist of insuring that the container is indeed sealed and that there is no surface contamination. Burials should not be permitted at fabrication sites where surface water could leach contamination from a failed container and enter the ground water. The remaining control would be test wells to monitor ground water level to permit removal if it should rise to the level of the waste.

Costs. Costs for on-site burial have not been estimated but the cost of contract burial has been assumed to be $1 per cubic foot exclusive of packaging and shipping. Packaging costs and shipping costs are assumed to average $5 and $3 per cubic foot, respectively. Water and air treatment costs were derived from BNW estimates for 1975 and scaled to the other years based on throughput ratios to 0.6 power. These costs are presented in Table V-31. The costs for waste control in the HTGR fuel fabrication plant are not included since the data were not readily available.

Power Reactor Operation

Technology Summary

A nuclear power plant consists primarily of a nuclear reactor which generates a hot coolant fluid and a turbine generator plant which converts the heat energy in the reactor coolant into electricity. At present, most of the reactors being built are cooled by light water and have metallic clad fuel rods containing uranium and plutonium oxide fuels. The high-temperature gas reactor (HTGR) is being developed and initial operation of large commercial units is expected in 1980. By 1990 about one-quarter of the power reactor capacity is expected to be HTGR's. The HTGR uses spherical particles of uranium and thorium oxide coated with silicon carbide and graphite and placed in a graphite matrix. A third type of reactor, the liquid metal fast breeder reactor (LMFBR), also is being developed and is expected to be introduced commercially in 1986. Only seven percent of the power reactor capacity is expected to be LMFBR's in 1990. The LMFBR is expected to have a liquid sodium coolant and a stainless steel clad fuel rod containing uranium and plutonium dioxides.

TABLE V-31. ESTIMATED COSTS TO CONTROL RADIOACTIVE RELEASES FROM FUEL FABRICATION PLANTS

Control Component	Cost in Thousands of Dollars 1975	1980	1985	1990
Air Filtration - UO_2 Plant				
Capital	6,720	8,560	11,550	17,400
Annual Operating	280	357	481	726
Air Filtration - PuO_2 Plant				
Capital	2,000	7,480	10,600	18,500
Annual Operating	100	370	530	930
Water Treatment - UO_2 Plant				
Capital	672	857	1,155	1,740
Annual Operating	56	71	96	145
Water Treatment - PuO_2 Plant				
Capital	250	934	1,325	2,320
Annual Operating	50	187	265	464
Solid Waste - UO_2 Plant				
Capital	15	20	26	40
Annual Operating	135	203	333	645
Solid Waste - PuO_2 Plant				
Capital	3	6	9	15
Annual Operating	7	49	87	224

Operation of power reactors creates radioisotopes by fissioning uranium and plutonium and by absorption of neutrons in the reactor components. Most of the fission products remain in the fuel elements and are shipped to the fuel reprocessing plants with the spent fuel. A small fraction escapes from failed fuel or by diffusion through the fuel cladding and enters the reactor coolant stream.

Reactor components that absorb neutrons to create radioisotopes are (1) fuel materials, (2) the coolant, (3) boron poison in the coolant, (4) coolant impurities, and (5) all reactor structural components and fuel cladding. These radioisotopes remain in the reactor or travel with the coolant until they are removed by (1) neutron absorption, (2) gas release in the off-gas systems, (3) coolant purification, (4) coolant leakage, or (5) removal of reactor equipment for disposal. The reactor waste treatment system is designed to collect all gases, liquids, and solids containing radioactivity and treat them to minimize radiation releases to the environment. Radioisotopes removed from the liquid and gas streams are packaged and shipped off-site for burial as solid radioactive wastes or are stored in cylinders as compressed gases. Residual radioisotopes that remain in the effluent liquids from the radwaste system are diluted to concentrations within the standards when released. Residual radioisotopes in the off-gases are diluted in ventilation air to concentrations within the standards and released. The radioactive waste flow diagram for power reactor operation is shown in Figure V-11.

Forecasting future waste facility capital costs requires considerable speculation at present. The current designs for waste systems are generally quite adequate for keeping waste releases far below permissible limits. However, current reevaluation of radiation limits may result in reduction of the permissible limits or of actual releases after 1980. In this study, it is assumed that current waste equipment systems are representative of the equipment in operation until 1980 and that "as low as practical" systems will be installed on all reactors starting operation after 1980.

The total quantity of waste releases was determined by analysis of past solid waste data and by use of the DOSIS computer code.(V-13) Solid waste data were collected for operating reactors and analyzed to determine typical waste generation rates.

The DOSIS code computes the quantities of liquid and gaseous wastes generated and then follows them through the waste treatment facilities to determine the amount that is released.

The computations in the DOSIS code are based upon Safety Analysis Report (Westinghouse ref. SAR,(V-14) Verplant SAR,(V-15) and Fort St. Vrain SAR(V-16)) data that represent equilibrium conditions. A follow-on study should undertake a comprehensive evaluation of the generation of radioactive isotopes in the coolant.

The capital and operating costs estimates for the waste treatment systems in existing reactor plants were based on the data in ORNL-4070.(V-17) The capital costs for reactors started up after 1970 were obtained from the CONCEPT(V-18) computer code of Oak Ridge National Laboratory of ORNL.

Emissions

There are three general types of radioactive wastes generated at power reactors--gaseous, liquid, and solid. A treatment system is provided for each type. Other significant environmental impacts result from heat releases and use of land.

In order to permit completion of this study as scheduled, several simplifying and general assumptions for description of the reactors and their effects on the environment were necessary. These were:

- Defective fuel includes faulty welds which leak only gaseous fission products and cracks which release the full spectrum of fission products.

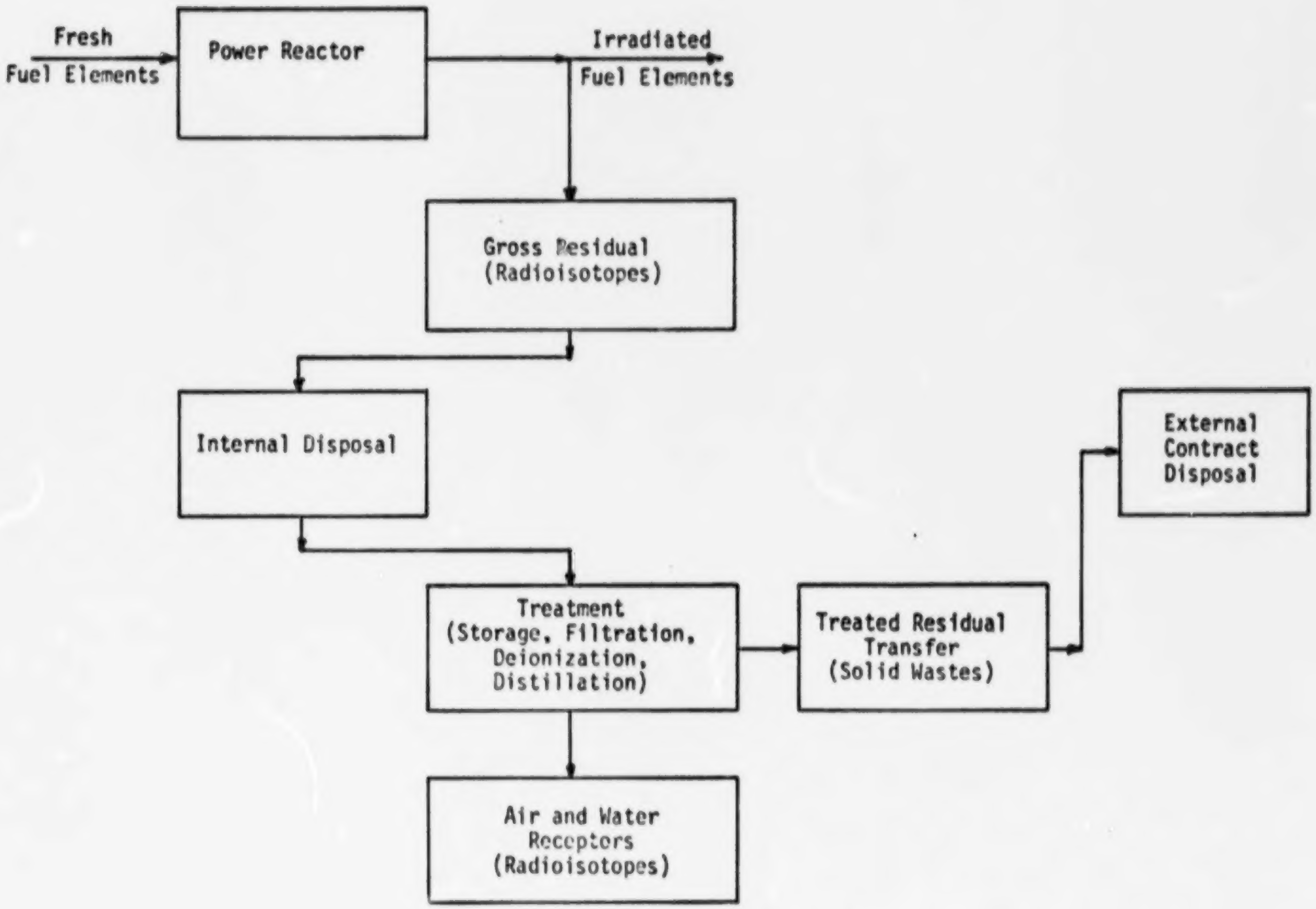

Fresh
Fuel Elements
Power Reactor
Irradiated
Fuel Elements
Gross Residual (Radioisotopes)
Internal Disposal
Treatment (Storage, Filtration, Deionization, Distillation)
Treated Residual Transfer (Solid Wastes)
External Contract Disposal
Air and Water Receptors (Radioisotopes)

FIGURE V-11. POWER REACTOR OPERATION

- Decommissioning will not be considered.

- Liquid wastes from HTGR's and LMFBR's are decontamination wastes, laboratory wastes, and laundry wastes after treatment.

- HTGR waste treatment is based on the Fort St. Vrain FSAR, plus bottling of rare gases for shipment to a permanent disposal site.

- LMFBR waste treatment is based on studies by Westinghouse Hanford Company.

Air. Radioactive gaseous wastes result primarily from release of fission product gases from failed fuel elements and absorption of neutrons by the reactor coolant and impurities in the coolant. These gases then are evolved from the coolant, particularly following pressure reductions during reactor outages and coolant purification operations, or from condenser vents.

The radioactivity of the gases is reduced primarily by decay, filtration, condensation, or absorption on activated charcoal. Decay occurs during storage in tanks or on charcoal beds for as long as several years. The gases are then filtered and released through the air ventilation exhaust system or sent to permanent disposal in suitable containers.

The radioactive gases released to the ventilation systems travel with the ventilation air and are released to the environment when the ventilation air leaves the ventilation stack. The gases continue to follow that air as it mixes with the atmosphere and are gradually diluted and dispersed in accordance with the turbulence of the atmosphere. Simultaneously, the quantity of radioactivity gradually decreases as the radioisotopes decay.

Radioactive particulates released to the atmosphere will gradually settle out or be washed out in accordance with the size of the particulates and the type weather. Noble gases generally will remain mixed in the atmosphere.

The radiation dose received by humans as a result of releases are dependent on many variables such as quantities of radionuclides released, locations of the people, and atmosphere conditions. The dose resulting from operation of a reactor can be predicted reasonably accurately only by a detailed study considering all variables for that reactor.

Water. Liquid wastes result from reactor coolant system leakage, reactor coolant purification, and numerous miscellaneous sources, such as laundry drains, equipment decontamination, pump seals, etc. The liquid wastes are collected in holding tanks, analyzed for radioactivity, treated (if necessary) to reduce the radioactivity, and then either re-used or released. The treatment usually is evaporation or ion exchange. The still bottoms or spent resins being handled as solid wastes.

The released radioactive liquids generally are released into the circulating water effluent system which then carries the radioisotopes into the receiving body. The release rate is such that the effluent is below the maximum permissible concentration. As a general rule, the receiving body is large enough or has a high enough continuous flow so that the radioisotopes are diluted to concentrations far below the maximum permissible under government standards.

The radiation dose received by humans using the water containing the radioisotopes depends primarily on the radioisotopes concentrations, the use of the water, and the contact time for the human. Typical examples of the human activities that result in dose are:

- Drinking
- Swimming
- Consuming aquatic life
- Boating
- Consuming foods irrigated with the contaminated water.

The dose received by humans as a result of releases to water is dependent on many variables. Again, the dose resulting from operation of a reactor can be predicted reasonably accurately only by a detailed study considering all variables for that reactor.

The quantity of cooling water required for removing the waste heat depends on the reactor thermal efficiency. An LWR requires about 1500 cfs of flow. The HTGR and LMFBR probably will need only about 1100 cfs. Part of this cooling water is evaporated during transfer of the heat to the atmosphere. The amount of evaporation is essentially zero for cooling with cold ocean water. On the other hand, a mechanical draft cooling tower may evaporate as much as 50 cfs.

Almost all plants built prior to 1970 used once through cooling. Most of these plants will probably continue to utilize this cooling method. A 1969 study by Wise and Cole(V-19) estimates that the heat sink capacity of major streams in this country would soon be used up. They broke the country down into 9 regions as shown in Figure V-12 and accumulated stream flow and temperature data for all rivers in the United States with minimum monthly average flows greater than 1000 cfs. In estimating the energy which could be added to each stream, they used the average flow in the month with the lowest total run off in the 1956-1966 time period. Table V-32 compares the anticipated projected increase in heat load from electrical plants built between 1965 and 1980 with the heat dissipation ability of the streams. It can be seen that in almost every area of the country, there is insufficient heat dissipation capability in the major streams.

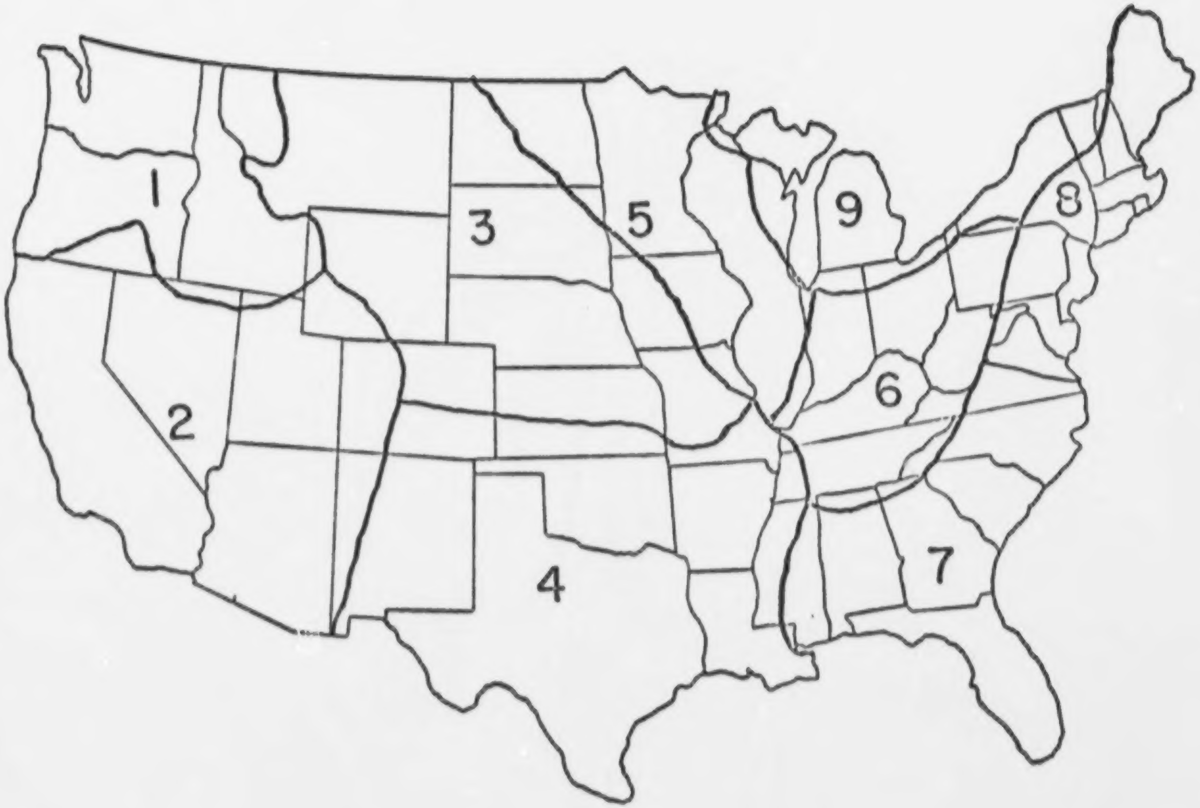


FIGURE V-12. REGIONAL DIVISIONS

TABLE V-32. COMPARISON OF PROJECTED HEAT RELEASED FROM THERMAL POWER PLANTS BUILT BETWEEN 1965-1980 WITH THE HEAT SINK CAPABILITY OF THE STREAMS

Region of Country	Projected Additional Power Generation 1965-1980	Heat Sink Capability of Streams in Region	Percent of Capacity
1	39	27.64	140
2	69	5.80	1190
3	26	10.96	240
4	74	24.36	300
5	48	4.56	1050
6	110	8.60	1280
7	85	7.68	1110
8	74	6.36	1160
9	33	60.48	55
Total or Average	558	156.44	(avg.) 356

The growth in regions 3, 5, 6, and 9 accounts for about 40 percent of the total increase in electrical demand. Except for region 9 cooling towers or ponds will have to be installed for almost every new plant in that area. The remaining 60 percent of the expected growth in capacity probably will be met by a combination of plants with ocean and tower cooling. If it is assumed that one-half of these plants have ocean cooling, one obtains a 70 percent/30 percent split between once through and close cycle cooling for all plants after 1980. Prior to 1980, there will be a build-up toward the 70/30 split since all plants built prior to 1970 will probably continue to use once through cooling. In 1975, based on present trends, about 20 percent of all nuclear reactors will be utilizing once through ocean cooling, 30 percent will be using cooling towers, and 50 percent will still be using once through fresh water cooling. By 1980, the percentages using once through cooling and closed cycle cooling will probably reverse. Based on these trends, Table V-33 was constructed to quantify the probable quantities of waste heat sent to the various receptors during the 1975-1990 time period.

Land. Each nuclear reactor is built in an exclusion area in which unrestricted public occupancy is not permitted. This exclusion area is designed according to the siting requirements of 10CFR100 which concern safety aspects of the facility. The size of the exclusion area is dependent on the reactor size, the design of plant safety systems, and the local meteorology. For a reactor which incorporates "as low as practicable" technology to control routine radioactivity discharges, the continuous radiation dose received by a person residing permanently at the edge of this exclusion area will satisfy the limits specified in proposed Appendix I to 10CFR50. Actual power plant sites usually are larger than the exclusion area and range up to several thousand acres.

TABLE V-33. RECEPTOR LOADINGS FOR HEAT DISSIPATED FROM NUCLEAR POWER REACTORS

Receptor	Gigawatts/Year 1975	1980	1985	1990
Streams and Rivers	53	72	72	72
Atmosphere	32	100	253	504
Ocean	21	60	126	233

The land actually occupied by the power plant is relatively small--on the order of twenty acres. The land required by the transmission system can be quite large, depending on the length of new line that must be built. As an example, a 300-foot wide right-of-way will occupy about 36 acres of land for each mile of length. In many cases, though, that land can still be used for agriculture.

Solid wastes consist of gas bottles, still bottoms, spent resins, obsolete or failed equipment, and miscellaneous wastes, such as paper, rags, used clothing, etc. Most solid wastes are packaged in 55-gallon drums, with or without concrete for shielding or solidification. Larger items require other appropriate containers designed primarily to prevent release of radioactive materials during handling. All solid wastes are shipped offsite for burial at licensed waste disposal sites.

Because radioactive solid wastes are not released to the land, there should be no radiation dose to humans as a result of direct contact with the radioisotopes. There is a small dose, though, that results from transportation of the wastes to the burial ground. As a general rule, the wastes are transported several hundred miles from the reactor plant to one of the few licensed commercial burial grounds. The drums of waste travel on trucks without external shielding. Persons in cars on the highways and in adjacent land area will receive radiation as the trucks pass by. Preliminary calculations indicate that this total dose for a 1000 MWe reactor is small (<0.1 man-rem/yr).

The quantity of solid radioactive wastes shipped to licensed burial grounds is dependent on the design of the radwaste systems. For "as low as practicable" systems the quantity is estimated to be from 1000 to 1700 drums per year per reactor.

Summary of Emission. Assuming that the HTGR's and LMFBR's have about the same environmental impacts as do LWR's, the potential environmental impacts can be expressed in terms of the impact per 1000 MW plant as shown in Table V-34. The total quantity of radioisotopes released in each of the four years considered in this study is presented in Table V-35.

TABLE V-34. POTENTIAL ENVIRONMENTAL IMPACT OF POWER OPERATION

Parameter	Typical Values per 1000 MWe Reactor
Heat releases	1500 to 2000 MW
Radioisotope releases[(a)]	
To air	~5×10^3 curies/yr
To liquids	~0.1 curies/yr
To burial	~10^4 curies/yr
	1000 to 1700 drums/yr
Land occupancy	
Transmission lines	36 acres/mile
Exclusion area	100 to 500 acres
Plant occupancy	~20 acres
Water evaporation	Up to 50 cfs
Cooling water flow	1100 to 1500 cfs

TABLE V-35. POWER REACTOR OPERATION-RADIONUCLIDE RELEASES TO THE ENVIRONMENT

	Curies		
		Water	
Year	Air	Lithium	Others
1975	9.4×10^6	2.7×10^5	339
1980	2.0×10^7	8.0×10^5	1,013
1985	2.6×10^7	1.8×10^6	3,430
1990	3.9×10^7	3.9×10^6	8,500

Control Mechanisms and Costs

The location and amount of heat released to the environment is controlled by the design of the cooling system. The choices range from the simpler once-through cooling systems on water bodies, which discharge all heat into the water body, to costly dry cooling towers, which discharge all heat to the air. The design selection is based on the environmental conditions around the individual reactor plants. The total installation cost ranges from about $8,000,000 for the simple once-through system to as much as $80,000,000 for dry towers. The annual operating costs range from about $500,000/year to as much as $8,000,000/year, exclusive of capacity penalties.

Some power plants have supplemental cooling towers that are operated only during critical periods of the year--such as the summer period when high river temperatures exist. Such systems generally are operated whenever undesirable water body conditions exist or during all weather conditions that do not result in undesirable water body conditions fogging or icing.

Release of radionuclides generally is controlled by (1) the design of the radwaste systems, and (2) the mode of operation of the radwaste systems. The initial control decision is the design decision since this generally determines the maximum treatment possible for the radwastes. The actual design can vary from essentially zero treatment of the wastes before release to the environment to intensive treatment resulting in "as low as practicable" or essentially zero release. The corresponding capital costs vary from about $3,000,000 to about $15,000,000 per reactor, and the annual operating costs from about $40,000/year to about $500,000/year per reactor.

The method of operating the radwaste system will determine the amounts of releases, particularly to water bodies. The most convenient method is to operate the system such that the releases result in radioisotope concentrations or doses well below permissible limits. It is possible, though, in some cases to operate the systems more intensively in combination with maximum recycle of treated water such that there is a much smaller release rate. Such operation may not be justified economically by the resultant minor reduction in the amount of radioisotopes released or in the reduction of population radiation dose, but may be justified from a political standpoint. The increase in total radiation dose received by plant employees may be more significant than the usually trivial reduction in dose to the general population.

Release of chemicals to water bodies generally are controlled by releasing the chemicals at a low enough rate that the dilution by the flow in the receiving body reduces the concentrations below applicable government standards. The operating costs for accomplishing such dilution generally are trivial. Generally, the extra construction cost for assuring proper dilution is trivial, but occasionally costs up to $1,000,000 may be necessary if special diffusers or long pipelines must be used. Similarly costs up to $1,000,000 may be necessary if a satisfactory water body is not available so that seepage or evaporation ponds must be used.

Releases of sanitary wastes generally are controlled by construction of sanitary treatment systems designed to meet government standards. Control then consists only of periodic inspection and maintenance, as appropriate.

Fuel Reprocessing

Technology Summary

Fuel assemblies which reach their goal exposure are discharged from the reactor, cooled (aged) and transported to the reprocessing plant. In the reprocessing plant the uranium, thorium and plutonium are separated from the wastes.

In the 1975 to 1990 time period, 95 percent of the reprocessed fuel will be irradiated in a LWR. The reprocessing technologies for HTGR, LWR, and LMFBR fuel are quite distinct at the head-end of the process. However, for the waste handling step the differences are very small. In addition, no commercial LMFBR or HTGR reprocessing plants have been built. When all these facts are combined the resulting conclusion is that the environmental impacts of the reprocessing industry can be most accurately assessed by using LWR reprocessing technology for each reactor concept.

The spent fuel from the reactor is transported from the reactor to the reprocessing plant in heavy shielded casks. The cask is unloaded and the fuel stored in a large water-filled pool. The fuel elements to be reprocessed are transferred to the head-end of the plant where the assemblies are sheared into 2-inch lengths to expose the fuel. The fuel is then dissolved with nitric acid in batch dissolving tanks. The leached hulls constitute a solid waste that is ultimately disposed of by land burial. During dissolution, volatile gases are released from the fuel and are collected in a gaseous waste processing system. The nitric acid solution of the fuel, containing uranium, plutonium, and nearly all the fission products is the feed solution to the solvent extraction process.

Nearly all major reprocessing facilities employ some form of Purex process(V-20) which makes use of the organic complexing compound tributyl phosphate (TBP), in an inert hydrocarbon diluent. Countercurrent extraction with the aqueous phase extracts the uranium and plutonium into the organic phase and leaves the fission products in the waste phase.

The containment of the volatile fission products, especially I^{131} is one of the most difficult problems in reprocessing. The gaseous wastes from the reprocessing steps are treated chemically as well as by filtration, sorption and scrubbing in order to reduce their radioactive content to levels that can be discharged to the atmosphere.

The LWR fuel being reprocessed has normally been cooled at least 150 days. At this time tritium, Kr^{85} and iodine are the important gaseous wastes. Inorganic iodine is removed by reaction with $AgNO_3$ impregnated on ceramic packing and by scrubbing with $Hg(NO_3)_2$-HNO_3 or caustic solutions.(V-21) Organic iodine, particularly methyl iodide, can be removed most efficiently by catalytic decomposition and sorption on silver, copper or iodine-impregnated charcoal. The efficiency of the iodine units is dependent on the concentration of iodine. A 99.6 percent efficiency is a commonly quoted design efficiency in cases where organic iodides are not removed.(V-22) With organic iodine treatment, efficiencies of 99.99 have been quoted.(V-23)

At the present time most reprocessing plants treat the off-gas streams only for iodine and particulates. Particulates are removed by sand filters,(V-24) deep bed fiberglas filters or a bank of high efficiency particulate air filters. Noble gas collection using cryogenic distillation(V-25) or absorption in fluorocarbons(V-26) are possible. There is no currently available tritium removal system.

It can be anticipated that all radioactive liquid wastes from fuel reprocessing will be evaporated and blended to yield only two streams: a high-level waste consisting of a highly concentrated solution of fission products and actinides and a low-level aqueous waste that has been sufficiently decontaminated of radioisotopes to permit it to be either discharged to the environment or recycled to the process.

Past practice has been to store the high level liquid wastes in large underground tanks. This process will probably be curtailed because of the difficulty in providing safe containment of the wastes from highly exposed power reactor fuels. Adequate liquid storage systems may simply be too large and costly as compared to the cost of early solidification. Solidified wastes would then be stored on site for several years prior to shipment to an off-site government repository.

In addition to the high-level aqueous treatment system, large volumes of process water containing low-level wastes are also present. Two to 500 gallons of contaminated water are produced for each metric ton of fuel processed. These streams, which contain about .1 percent of all the fission products, can be decontaminated by a factor of 10^5 for all isotopes except tritium. At the present time tritium must either be discharged into the area streams or sent into the atmosphere as water vapor. The following paragraphs taken from an Oak Ridge summary report(V-21) puts the tritium discharge levels in perspective.

Tritium is produced in the fission of U^{238} and PU^{239}, with yields of about 0.01 percent and 0.02 percent, respectively.(V-27) It merits special consideration from the standpoint of its management in fuel reprocessing because it is unresponsive to separation and concentration by conventional procedures for treating waste.(V-28,V-29) In fuel reprocessing, less than 1 percent can be expected to volatilize during the dissolution of oxide fuels.(V-30) There is experimental evidence that tritium tends to escape from oxide fuels during reactor operation;(V-31) however, the tritium remaining with the fuel can be expected to appear as tritiated water in the reprocessing plant evaporator condensates.

If this tritium could be uniformly dispersed throughout the environment, the resulting increase in background would be of little significance.(V-32) In the actual case, however, a fuel-processing plant will have only its immediate environs available for dispersion, and the capacity of these environs to accept tritium will depend on the rate that the latter is released, as well as on the many environmental factors that pertain to the particular site.

Two immediately available possibilities for the release of tritium-bearing wastes under existing regulations are: (1) dilution and release directly to surface waters, and (2) distillation into the plant off-gas system and subsequent release up the stack.

The quantity of tritium that can be released to surface waters can be computed within the limitations that the concentration shall not exceed the permissible concentration in water under 10CFR20, or $3x10^{-3}$ μc/cc at the boundary of the controlled zone, and that the concentration shall subsequently not exceed $1x10^{-3}$ μc/cc for the general population. If the controlled zone borders a stream of any significant size, the first of these restrictions is controlling.

A ton of fuel irradiated to a burnup of 33,000 MWd contains about 700 curies of tritium, which would require dilution in water to the extent of about 63 million gallons before it could be released from the controlled zone at the permissible concentration of 3.10^{-3} μc/cc. The total aqueous effluent from a plant operating with a Purex process flowsheet may be as much as 10^6 gallons per ton of fuel processed, but this is far short of the requirements for tritium dilution. The most practical means of achieving the on-site dilution requirements would be to have available, for this purpose, a stream flowing through the controlled area. To meet the specification for use by the general population, this stream would have to flow into a larger body of water to achieve additional dilution by a factor of 3 or more.

It is desirable that a plant be situated adjacent to a large, preferably navigable, river for other (and possibly more important) reasons than tritium disposal; however, it is much less obvious that acceptable sites should be limited to those which, in addition, encompass a stream of the size useful for dilution. Therefore, we conclude that, with restrictions as presently interpreted, the alternative of release to surface waters is of very limited applicability as a general case.

Distillation into the plant off-gas provides a more effective means of releasing tritium. Calculations presented in Section 8 of Reference V-21 indicate that plants having spent fuel capacities up to 20 metric tons per day and site boundaries two to three km distant can release their tritium in this manner under existing regulations. This is not to imply, however, that attempts should not be made to develop methods for removing tritium, before it becomes greatly diluted with air or process streams, and encapsulating it for a long-term storage.

Emission

In this section the emissions will be expressed in terms of a 5 ton per day reprocessing plant operating at 75 percent capacity. In one year this plant has a throughput of 1370 metric tons of heavy metal. This is equivalent to the discharge from reactors having a total installed capacity of 50 GW. Table V-36 shows the projected demand for fuel reprocessing. Current plans project a 1986 startup date for the HTGR plant. Thus, no fuel reprocessing demand is shown in Table V-36 until 1990 for the HTGR. The environmental impacts of plant operation on the air, water, and land will be discussed sequentially. A waste flow diagram for reprocessing is shown in Figure V-13.

TABLE V-36. REPROCESSING PLANT THROUGHPUTS

	Metric Ton/Year			
	1975	1980	1985	1990
LWR	1300	3400	5500	10,100
HTGR	0	0	0	820
LMFBR	0	3	7	540

Air. The emissions from the reprocessing plant operations to air are summarized in Table V-37. The reprocessing plant has two major impacts. One is the release of radioactive gases and particulates. The second is the decay heat from the radioactive materials in the reprocessing plant. In addition some iodine and some volatile rare earth chemical compounds are released. The technology exists to routinely collect these gases. It is assumed that all new reprocessing plants coming on line after 1975 will be able to remove 99.99 percent of all the radioactive gases.

The table on particulate and gas releases was left blank since their major effect was included under the radiological release heading.

In calculating the heat load, the energy released through radioactive decay was assumed to be released directly to the air. Another source of heat is the evaporators and concentrators in the reprocessing plant. It was estimated that this load was about equal to the heat generated by radioactive decay and this heat was taken up by the process cooling water stream.

Water. The major environmental impact of a reprocessing plant on water results from the requirement for large volumes of process water. It is estimated that a 5 MT/day reprocessing plant needs about 2,600 gpm of process and cooling water.(V-21) Older plants discharged some waste streams from the plant. However, newer plants continually clean up and reuse all their process water and a cooling water system would be uncontaminated. The releases to water are summarized in Table V-38. There are no radiological releases to the water from any plants other than these already licensed. As was mentioned in the section on air releases, half

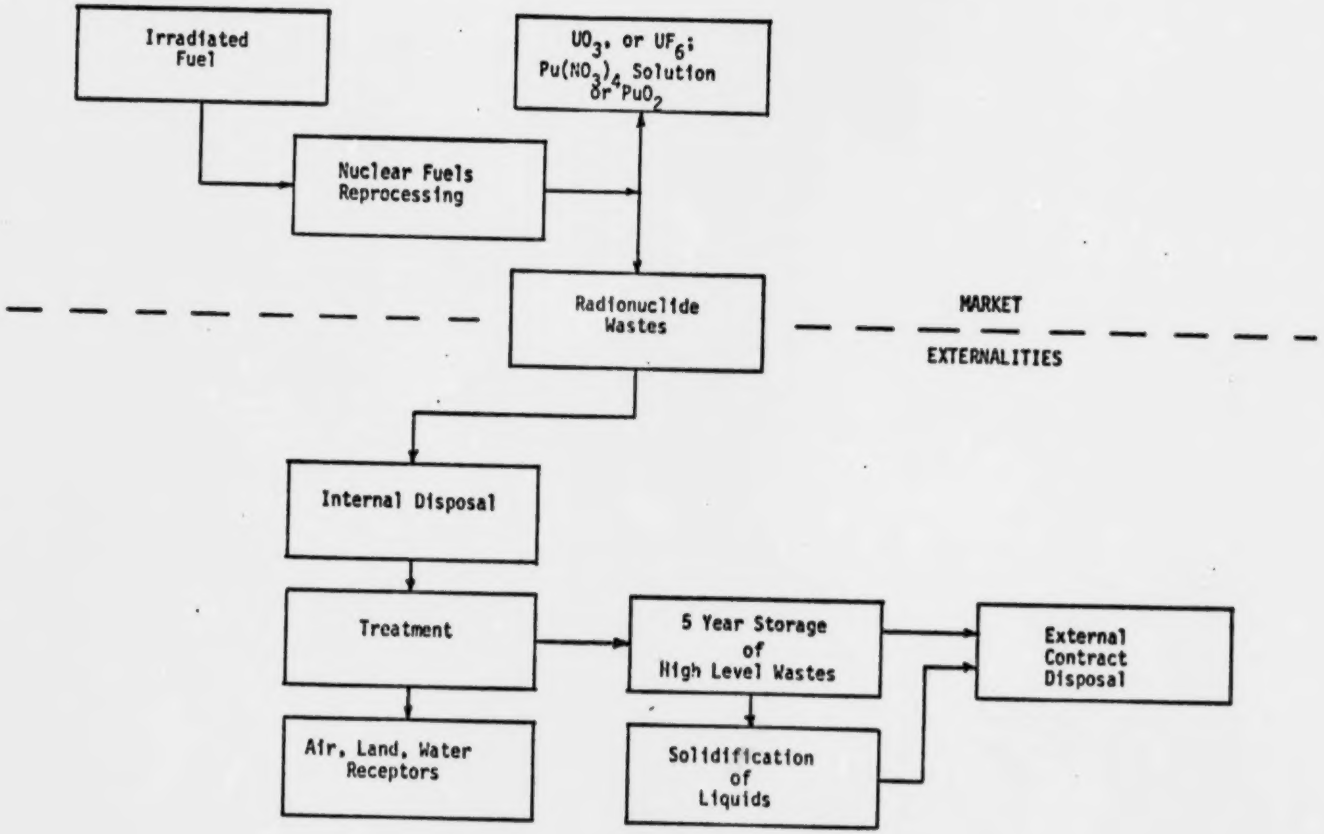

Irradiated Fuel
Nuclear Fuels Reprocessing
UO$_3$, or UF$_6$; Pu(NO$_3$)$_4$ Solution or PuO$_2$
Radionuclide Wastes
MARKET
EXTERNALITIES
Internal Disposal
Treatment
Air, Land, Water Receptors
5 Year Storage of High Level Wastes
Solidification of Liquids
External Contract Disposal

FIGURE V-13. NUCLEAR FUELS REPROCESSING

the thermal load on the reprocessing plant was assumed to be discharged in the cooling water stream. The bottom part of Table V-38 summarizes the projected heat loads on the water for all the reprocessing plants in the time period of interest.

Land. The reprocessing plant produces both high and low level radioactive wastes. Both will be solidified to minimize their mobility and then shipped off site for disposal. Table V-39 gives the curies and volumes of high level waste shipped off site. It is assumed that they have been stored for five years on site prior to shipment for perpetual storage at a government repository. It is estimated that 200 ft^3 of low level waste are generated for each ton of fuel reprocessed.(V-21) The major source of radiation from the low-level wastes is the cladding hulls. The curies and volumes of these wastes packaged and sent to a licensed contractor are shown in Table V-40. It is assumed that these wastes are transported soon after the fuel has been reprocessed.

Control Mechanisms and Costs

The LMFBR, HTGR, and the LWR reprocessing plant waste treatment systems can be considered to be similar even though the processes are quite distinct.

The primary sources of waste are: the fission productions separated from the thorium, uranium, and plutonium recycle streams; the trans-plutonium isotopes; small percentages of the uranium, thorium, and plutonium; and activated or contaminated processing material.

TABLE V-37. ENVIRONMENTAL EFFECTS OF FUEL REPROCESSING ON AIR

	1975	1980	1985	1990
Radiological			Curies/Year	
LWR	1.0x10^7	1.7x10^7	1.9x10^7	2.1x10^7
HTGR				9.5x10^5
LMFBR		small	small	4.7x10^5
Total	1.0x10^7	1.7x10^7	1.9x10^7	2.2x10^7
Particulate and Gas			Tons/Year	
LWR				
HTGR				
LMFBR				
Total	nil	nil	nil	nil
Thermal			MW	
LWR	24	62	100	180
HTGR	0	0	0	30
LMFBR	0	<1	<1	20
Total	24	62	100	220

TABLE V-38. ENVIRONMENTAL EFFECTS OF FUEL REPROCESSING ON WATER

	1975	1980	1985	1990
Radiological		Curies/Year		
LWR	$2x10^4$	$2x10^4$	$2x10^4$	$2x10^4$(a)
HTGR	0	0	0	0
LMFBR	0	0	0	0
Total	$2x10^4$	$2x10^4$	$2x10^4$	$2x10^4$
Water Usage		Gpm		
LWR	3,000	7,000	11,000	20,000
HTGR	0	0	0	1,600
LMFBR	0	nil	nil	2,200
Total	3,000	7,000	11,000	24,000
Thermal		GWt		
LWR	24	62	100	180
HTGR	0	0	0	30
LMFBR	0	<1	<1	20
Ttoal	24	62	100	220

The reprocessing plant waste treatment systems can be subdivided into gas, liquid, and solid treatment systems. Ultimately the solid and liquid streams are combined so only two systems are needed. The gas treatment systems are estimated to comprise about 10 percent of the total reprocessing plant cost.(V-33) Thus, based on 1970 costs, the gas treatment facilities for a 5-ton per day plant valued at 66 million would cost 7 million dollars. The annual operating cost of these facilities is about 1 million dollars. In the near future additional off-gas treatment facilities to collect noble gases will probably be required. It is estimated that the additional treatment would add another 10 percent to the total plant cost.(V-21) Thus, in the near future many plants may be required to add additional off-gas treatment equipment which will cost about 7 million dollars to procure and install. The annual operating cost of the plant will probably increase by about 1 million dollars a year as a result of this additional equipment.

The costs incurred from the solid waste treatment facility are not very sensitive to the process used. For this analysis it will be assumed that the wastes are immediately solidified and then stored for five years prior to sending them to the government waste repository. For a 5 ton/day reprocessing plant, the waste treatment facility total installed cost is estimated to be about 18 million dollars. Annual operating costs are estimated to be $1.9 million/year.(V-21,V-34)

TABLE V-39. CURIES AND VOLUMES OF HIGH-LEVEL WASTE SENT TO A GOVERNMENT REPOSITORY FOR PERPETUAL STORAGE

	1975		1980		1985		1990	
	curies/yr	ft^3/yr	curies/yr	ft^3/yr	curies/yr	ft^3/yr	curies/yr	ft^3/yr
LWR	0	0	1.3×10^9	1300	3.4×10^9	3400	5.5×10^9	5.5×10^3
HTGR	0	0	0	0	0	0	0	0
LMFBR	0	0	0	0	4×10^6	3	8×10^6	7
Total	0	0	1.3×10^9	1.3×10^3	3.4×10^9	3.4×10^3	6.5×10^9	5.5×10^3

TABLE V-40. CURIES AND VOLUMES OF LOW LEVEL WASTE PACKAGED AND SENT TO A LICENSED REPOSITORY FROM THE REPROCESSING PLANTS

	1975		1980		1985		1990	
	curies/yr	ft^3/yr	curies/yr	ft^3/yr	curies/yr	ft^3/yr	curies/yr	ft^3/yr
LWR	2.9×10^5	2.6×10^5	7.5×10^5	6.8×10^5	1.2×10^6	1.1×10^6	2.2×10^6	2.0×10^6
HTGR	0	0	0	0	0	0	$<10^5$	1.1×10^5
LMFBR	0	0	7.4×10^5	6.8×10^5	1.7×10^6	1.4×10^3	1.3×10^8	1.6×10^5
Total	2.9×10^5	2.6×10^5	1.5×10^6	6.8×10^5	2.9×10^6	1.1×10^6	1.3×10^8	2.3×10^6

Radioactive Waste Disposal

Technology Summary

The solid radioactive wastes generated by the nuclear power industry are classified primarily in accordance with the level of radioactivity and the disposition of the wastes. A flowsheet is given in Figure V-14.

The high-level wastes are defined as the wastes containing most of the radioactive fission products separated from the irradiated fuel elements at the reprocessing plants. These intensely radioactive materials produce most of the highly-penetrating radiation in the nuclear power industry outside of the reactor primary loops and also contain significant quantities of plutonium. They currently are scheduled for storage in special repositories with an extremely low probability of release to the environment.

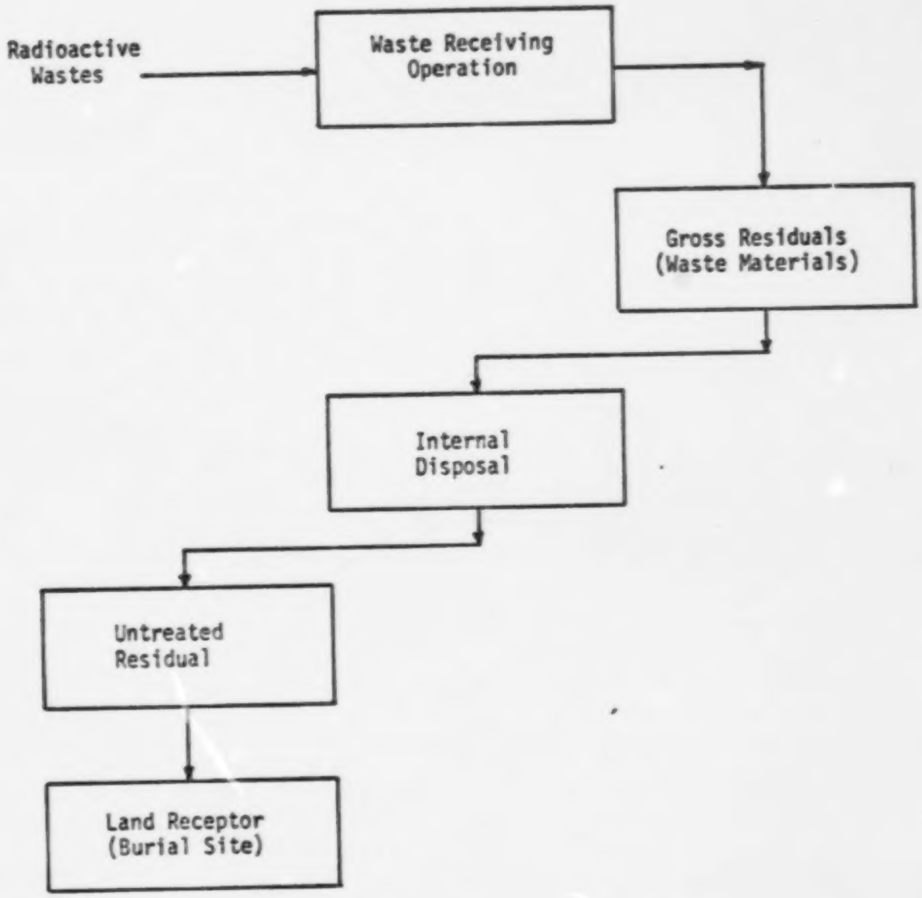
The low-level wastes are defined as all other radioactive wastes and generally have relatively low radiation levels even without shielding. Because of these lower radiation levels, it is considered satisfactory to package and store them in locations where they can be collected for eventual burial at licensed waste disposal sites.

Currently low-level radioactive materials generated in the nuclear power industry are packaged in leak-proof containers for transit (usually 55-gallon drums) and shipped off site to commercial burial sites. These materials consist of a multitide of items such as floor sweepings, spent resins, waste still bottoms, failed or obsolete equipment, etc. Most of it contains relatively small amounts of radioactivity; but some, such as burned-out power reactor control rods, contain thousands of curies of radioactivity.

When the materials are received at the disposal site, they are simply dumped into a burial trench and covered with a layer of dirt. The trenches are built in locations where the expected eventual failure of the waste containers is not expected to result in travel of the radioactive materials away from the burial site. This is achieved by choosing locations where the materials will be stored above the water table and there is little probability that the wastes would be washed down to the water table. As a general rule, however, the radioactivity of these wastes is low enough that the burial sites could be re-entered and wastes repackaged, if environmental monitoring shows that there could be an uncontrolled release to the environment.

There is no treatment of surface burial wastes at the burial sites. The shipping containers are designed to prevent release of radioactive materials during transportation and burial.

High-level radioactive wastes currently are stored as liquid solutions in tanks. After 1975, all such wastes are expected to be solidified and stored in permanent engineered storage. Economic analysis shows that the



Radioactive Wastes
Waste Receiving Operation
Gross Residuals (Waste Materials)
Internal Disposal
Untreated Residual
Land Receptor (Burial Site)

FIGURE V-14. RADIOACTIVE WASTE DISPOSAL

best procedure is to store the wastes for several years at the reprocessing plant to permit decay of the short half-life radioisotopes. This reduces the heat-generation rate and radiation hazard during shipment and storage in the permanent facilities. The wastes may be temporarily stored as either liquid solutions or solidified wastes at the reprocessing plant site; the choice depending on the physical form of the wastes when discharged from the fuel separations process.

In this study the wastes are assumed to be stored for five years (about the optimum period) before shipment to the mines. The wastes are encapsulated before shipment, and are stored in the permanent facility without removal from the capsules or treatment.

The low level activity wastes include only materials received from private nuclear industry in the areas of feed materials conversion, fuel fabrication, and reactor operations. All wastes are received ready to bury. It excludes materials from the uranium mills and mines. This activity includes only radioactive materials permanently buried at commercial surface burial waste sites. It does not include materials sent to deep burial sites or materials buried near the surface at other sites. This account does not include samples, failed equipment, etc., shipped from production plants to research facilities or government bodies for analyses and investigations of equipment performance.

The high level activity wastes include only materials expected to be placed in permanent engineered storage and all wastes are received ready for storage. The material buried consists only of highly radioactive materials, primarily fission products, from fuel reprocessing plants.

Environmental Impact

Environmental impacts in disposing of radioactive waste involves only land use. There is no escape of radioactive materials from the burial sites to the air or adjacent water tables. The amount of material to be handled and its activity for each of the years 1975, 1980, 1985, and 1990 are given in Table V-41.

TABLE V-41. SUMMARY OF RADIOACTIVE WASTE

	1975	1980	1985	1990
Amount, cu ft	1.5×10^6	2.9×10^6	5×10^6	10×10^6
Activity, curies	5.7×10^6	1.3×10^9	3.4×10^9	5.5×10^9

Transportation in the Nuclear Industry

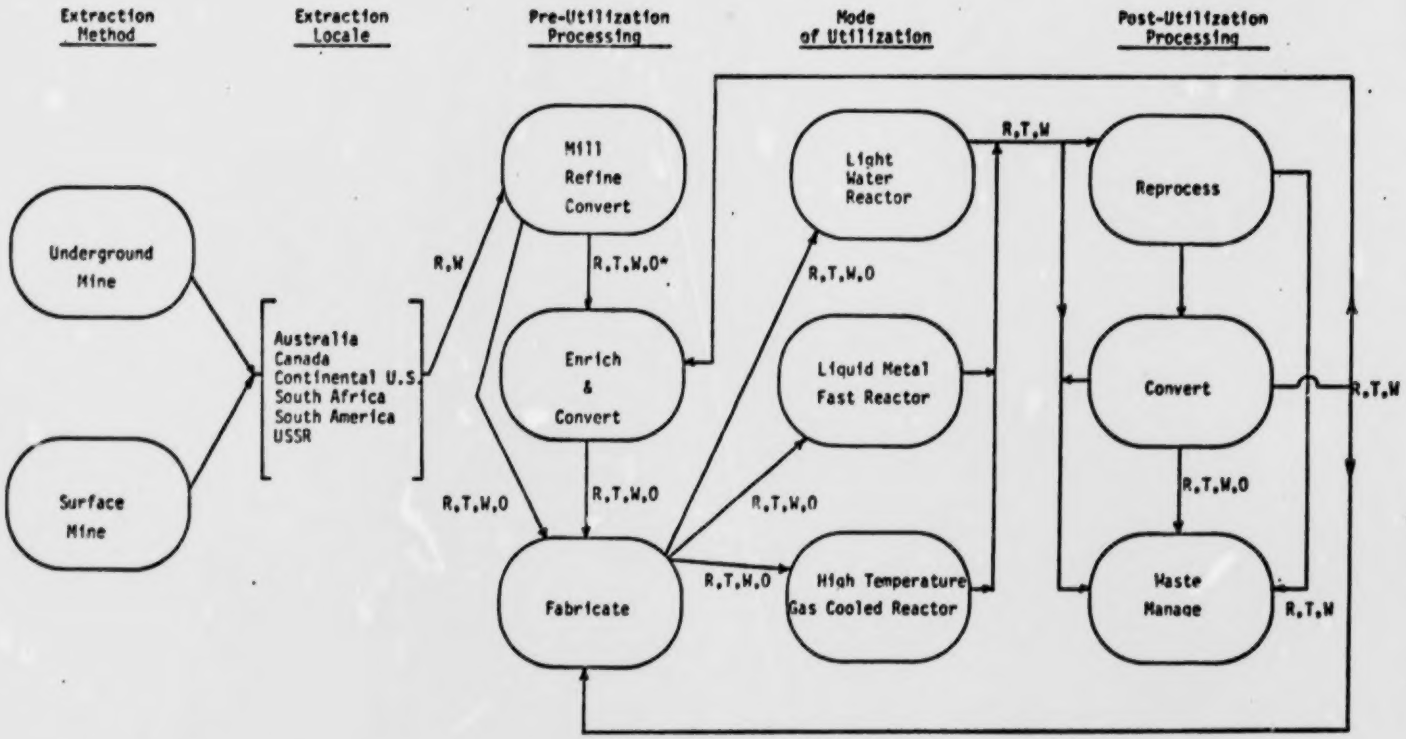
Transportation of various materials is required to link the various steps indicated in Figure V-1 which is in the Technical Approach Section of this report. A process flowsheet for transportation is given in Figure V-15. Railroads are the primary mode of transporting nuclear materials in the nuclear power industry with shipments by truck being the secondary mode. The principal means of water transportation would be transcontinental freighter. In some steps of the process, the shipments would not go off-site.

The quantities of nuclear materials that will be shipped in the years 1975, 1980, 1985, and 1990 are given in Table V-42. The industrial chemical shipments needed to support the processes are not included. In general, except for accidents, the impacts of shipments of nuclear materials is identical to transportation of any other material. The usual requirements for use of right-of-way, energy consumption, and capital equipment acquisitions have their normal impact on the environment. The impact of accidents has not been evaluated since this would require a statistical analysis of the frequency and severity of accidents for similar types of materials. All nuclear materials are in innocuous form or are packaged to minimize loss of control of the material in the event of an accident. Thus, the cleanup after an accident presents no greater problem than any other industrial chemical shipment.

The AEC and others are currently conducting statistical evaluations of the frequency and severity of accidents and the attendant risk for shipments of spent fuel, recovered plutonium, and wastes. If we assume an accident, the following is a ranking of materials from the most hazardous, if prompt and effective cleanup steps are not taken.

Material Being Shipped

- Plutonium
- Spent Fuel
- Wastes
- UF_6
- Fuel Elements
- UO_3
- U_3O_8
- ThO_2
- Thorium Ore


Extraction Method
Extraction Locale
Pre-Utilization Processing
Mode of Utilization
Post-Utilization Processing
Underground Mine
Surface Mine
Australia
Canada
Continental U.S.
South Africa
South America
USSR
R,W
R,T,W,O
Mill Refine Convert
R,T,W,O*
Enrich & Convert
R,T,W,O
Fabricate
R,T,W,O
R,T,W,O
R,T,W,O
Light Water Reactor
Liquid Metal Fast Reactor
High Temperature Gas Cooled Reactor
R,T,W
Reprocess
Convert
R,T,W,O
Waste Manage
R,T,W
R,T,W

*Nomenclature

R,T,W are Rail, Truck, Water Transportation and O is on-site.

FIGURE V-15. NUCLEAR (FISSION) FUEL CYCLE PROCESS FLOWSHEET

TABLE V-42. NUCLEAR MATERIAL SHIPMENTS
(Tons)

Material	1975	1980	1985	1990
Uranium Ore	9.6×10^6	16×10^6	28×10^6	44×10^6
Thorium Ore (Reactor use)	180	6700	25×10^3	52×10^3
U_3O_8	18×10^3	31×10^3	53×10^3	84×10^3
ThO_2 (Reactor use	7	270	1000	2100
UF_6 to enrichment-natural	23×10^3	39×10^3	67×10^3	105×10^3
-Recovered	1900	5000	8100	15×10^3
UF_6 to fabrication	4450	6650	13300	21×10^3
Fuel Elements - LWR	5100	8900	15×10^3	23×10^3
- HTGR	40	3100	9×10^3	21×10^3
- LMFBR		5	12	2600
Spent Fuel - LWR	2000	5600	9×10^3	17×10^3
- HTGR				9400
- LMFBR		5	12	900
UO_3 - Recovered uranium	1500	4000	6600	12×10^3
Plutonium	3	31	63	150
Waste	1.5×10^6 cu. ft.	2.9×10^6 cu. ft.	5×10^6 cu. ft.	10×10^6 cu. ft.

* Net weight of material indicated does not include container, shielding, or protective packaging which in the case of spent fuel and plutonium is of the order of 50 times the weight of the material and must make the return trip empty.

- Uranium Ore

This ranking is based upon the relative toxicity and chemical stability of the compounds and makes no judgment regarding the effectiveness of the container or shipping regulations. The fuel elements are ranked above UO_3 since they may contain plutonium, and below UF_6 because of their chemical and physical stability.

We have assumed that no releases occur during the transport of nuclear materials between process steps of the fuel cycle simply because we have assumed normal operational conditions. Therefore, control mechanisms and associated costs were not studied.

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APPENDIX W

ADVANCED ENERGY SYSTEMS

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APPENDIX W

ADVANCED ENERGY SYSTEMS

Summary

The objective of this phase of the study was to identify potential advanced energy systems, to identify the environmental burdens, and to rank the systems environmentally.

In order to rank the prospective energy systems environmentally, consideration must be given to a wide range of factors. In many cases, it is not possible to develop quantitative measures of the extent of environmental burden. More important, there is not yet available a method for comparing emissions. For example, it is not possible to trade, quantitatively, cooling water requirements for air pollutant emissions. Thus, for present purposes it has been necessary to make qualitative judgments of the relative significance of many environmental burdens. Consideration has been given to cooling water requirements and emissions of common air pollutants; land requirements for solar energy collectors and for strip mining; to problems associated with a large variety of waste products; to the potential for local or meso-scale climate modification; and many others.

Each energy system was considered in terms of both real and potential environmental burden. They were then grouped relative to each other into four qualitative classes, from excellent to poor, to reflect increasing environmental burden. Consideration was given not only to adverse factors; any environmental gains were also considered. For example, breeder reactor systems were credited for negative fuel consumption; solid waste utilization in steam electric plants received credit both for its contribution to the reduction of solid waste disposal problems and for reducing the need for virgin fuels.

Some of the systems can be considered to be rapidly emerging technology; some of the environmental factors charged against them may be resolved soon. In some cases, there is conflicting information as to the potential burden. In most cases, the scientists and engineers who are closely associated with a particular system tend to be very optimistic about the potential of that system to provide significant energy at relatively modest environmental cost. Considerable effort was devoted to achieving a balance and avoiding excessive optimism or pessimism.

The rankings of the selected advanced energy systems are presented in Table W-1. Those considered capable of producing significant power in the future are identified.

TABLE W-1. ENVIRONMENTAL RANKING OF ADVANCED ENERGY SYSTEMS

Excellent

Solar Energy (Residential)(c)
Heat Pumps (Residential, Electric)(c)
Conventional Hydroelectric(a)

Good

Tidal
Geothermal (Hydrocracked dry rock)(c)
Solar (Rankine cycle)(c)
Solar (Stirling)(c)
Geothermal (Natural)(b,c)
Fusion
Solar (Satellite)
Solar (Photovoltaic)
Natural gas/steam/electric(a)

Fair

Geothermal (nuclear stimulated)
Magnetohydrodynamic (Closed cycle, nuclear)(c)
Breeder reactors (gas-cooled(c), liquid metal(c), and molten salt)
Fuel Cells (Coal-to-hydrogen gasification)(c)
Light Water Nuclear Reactors(a,b,c)
Fuel Cell (Nuclear-electrolytic hydrogen)(c)
Thermoelectric (Solar)
Gasified coal/steam/electric(c)
Solid Waste Utilization (Trash-coal/steam/electric)(b,c)
Magnetohydrodynamic (Open-cycle - coal/steam/electric)(c)

Poor

Coal/Steam/Electric(a)
Thermionic (Nuclear)

(a) The conventional systems in 1972 are included for reference purposes only.
(b) Capable of producing significantly increased energy by 1975.
(c) Capable of producing significant energy by 1990.

Much of the reasoning behind the relative positions assigned to the various systems can be illustrated briefly as follows.

Fuel cell systems have at least two advantages over conventional steam electric systems; they are more efficient thermally and would produce substantially less air pollution. These advantages may be illusory, however, because the fuel production would represent an additional step which would reduce overall efficiency. Moreover, if the fuel is produced by gasifying fossil fuels, there would be some production of conventional air pollutants.

The solar energy systems are widely considered to be environmentally "clean". However, the collectors would require the dedication of very large land areas. Systems using satellite collectors would require beam transmission of the energy to receivers on the ground. Some concern has been expressed for the potential hazard associated with the relative intensity of the proposed beam of electromagnetic radiation.

Residential heat pumps represent largely beneficial environmental impact because they would reduce the load on central power plants. On the other hand, there would be a requirement for supplementary space heating at times for which resistance heating systems appear attractive. In that case, widespread use of heat pumps might lead to increased central power station load, with attendant environmental insults, during the heating season.

The various approaches suggested for utilizing geothermal energy are all site limited, and all appear to require dedication of substantial amounts of land, much of which is presently scenic. In addition, there is a potential for the contamination of surface water with dissolved salts, and for air pollution with hydrogen sulfide or ammonia, for example. Concern has also been expressed over possible subsidence of relatively large areas, and for possible seismic activity as a result of deep well injection.

Controlled Thermonuclear Fusion reactors have several potential advantages over fission reactors and fossil-fueled plants. They should be more efficient, thus requiring less cooling capacity; there will be no combustion products; and radioactive wastes will be largely contained. However, there will be substantial tritium production, and the reactor structures will be radioactive.

Utilization of tidal currents to produce electricity is attractive as a nonpolluting system. However, there are several environmental factors, including alteration of estuaries, both physically and biologically, and the potential for local or meso-scale alteration of weather and climate.

Solid waste combustion in thermal electric plants has already been mentioned for its overall beneficial environmental effects. A system utilizing solid waste would produce similar air pollution except appreciably reduced sulfur emissions and possibly increased heat rejection problems as compared to a conventional coal-fired plant.

Breeder reactors as a group have similarly been mentioned as having a decided environmental advantage because of their fuel production as opposed to consumption. However, their thermal efficiency is not altogether favorable, and their production of tritium and fission products which must be stored for decay represent adverse environmental factors. In addition, the shipment and reprocessing of fuel in large quantities represents a certain environmental risk because of the possibility of accidents.

Magnetohydrodynamic power systems have received much favorable attention largely because of their relatively high thermal efficiency. Seed recovery must be thorough for economic as well as environmental reasons, but it is not known how important might be the escape of relatively small amounts, by weight, of very small diameter seed particles which are extremely difficult to capture. Sulfur recovery within the system is a decided bonus but the very high temperatures associated with MHD will tend to enchance production of oxides of nitrogen.

Thermoelectric and thermionic systems are not expected to provide any significant power to meet national demands by 1990 or beyond.

The more complete detailed descriptions of the selected advanced energy systems are presented in the following section. It should be recognized that the order in which they are presented is not necessarily the order of environmental ranking nor energy potential which is presented in Table W-1.

Fuel Cell Energy Systems

A fuel cell is an electrochemical energy conversion device that can continuously produce electrical energy from an input of chemical fuel and oxidizer. The fuel cell is not limited as Carnot cycle systems and theoretically can achieve higher energy efficiency. However, high capital costs prevent fuel cells use for large-scale central station power generation. Fuel cell power plants are more competitive in smaller sizes (<50 MW) for dispersed power generation. The problems of conversion of DC as generated in the fuel cell to AC as used universally at present must also be considered along with the costs of such conversion when it is required.

Fuel cells can be roughly classified by type of electrolyte:

Aqueous electrolytes: temperature range, 0-200 C
Molten salt electrolytes: temperature range, 500-700 C
Solid electrolytes: temperature range above 700 C

The lower temperature aqueous electrolyte type fuel cells hold the most promise for the future. Oxygen in the air is used as the oxidizer and hydrocarbons and hydrogen are the principal fuels of interest.

Four specific fuel cell systems of interest are described here, together with an appraisal of their acceptability.

System 1

Natural gas distributed by pipeline is the fuel and oxygen in the air is the oxidizer. The fuel cell power plant consists of three subsystems: (1) a steam reformer to convert methane to hydrogen and carbon dioxide, (2) the fuel cell stacks, and (3) a DC to AC inverter. There are several possible applications being studied that can be grouped according to size and location:

System 1A	12-50 kw	Residential/commercial
System 1B	10-20 MW	Substation
System 1C	100 MW	Central station.

System 1A. This has been the subject of the $50 million TARGET program of Pratt & Whitney Aircraft (P&WA) and the gas utility industry, begun in 1967, and now in the second phase of field test.(W-1) The principal limitation has been capital cost which has been decreased from about $1500/kw in 1968 to about $400/kw in 1972 with forecasts of $200 to $250/kw during commercial production (Phase 3). Because of the dependence on natural gas, it is unlikely that this system will find wide application before the 1980's when coal gasification will provide a reliable supply of synthetic gas (methane).

System 1B. This is similar to System 1A and is the subject of current studies for the electric utility industry(W-2) to realize the advantages of dispersed siting on the electric power network (electric transmission savings) for either base load or peaking duty with estimated installed costs of $140 to $165/kw and $110 to $135/kw, respectively. For substation use, versatility in operation on other fuels is required in addition to natural gas, such as, propane and low-sulfur liquid fuels. Estimates of cost goals indicate that to be competitive with nuclear energy, fuel cell fuel costs would have to be below $\$0.80/10^6$ Btu; to be competitive with gas turbines fuel cost could be in the range of $0.80 to $\$1.10/10^6$ Btu. Whether the system's goals can be achieved will be determined by about 1976 with potential use by 1980. Near-term use is limited by supply of natural gas and low sulfur liquid fuels; long-range use is dependent on development of synthetic gas (methane) by coal gasification in the 1980's.

System 1C. Use of fuel cells for large-scale central station power generation does not appear promising with present fuels or future synthetic fuels because the efficiency advantage of fuel cells over steam and gas turbine systems decreases as power output increases to 100 MW and larger (see Figure W-1). Also a principal savings for fuel cells is in dispersed use with pipeline transmission of gas energy where credit for savings over electric transmission can be realized.

System 2

Hydrogen gas produced from coal and distributed by pipeline is the fuel and oxygen in the air as the oxidizer. The fuel cell power plant is simpler and lower cost than System 1 since an integral reformer is not needed. For use of pipeline hydrogen, it is questionable that fuel cells could be dispersed to the single residence level. Thus, the urban energy system currently under study by Battelle at about the 1 MW level appears optimum for safety while retaining most of the economic and esthetic advantages of underground gas transmission as opposed to overhead electrical transmission and retaining the option for utilization of waste heat.

System 3

Nuclear energy (fission or fusion) can be the primary energy source to produce low cost electrical energy which is used to produce hydrogen by water electrolysis (other schemes for direct production of hydrogen from water by nuclear energy are presently remote possibilities). Hydrogen then becomes the energy carrier via underground pipelines for dispersed utilization of fuel cells at urban load centers as in System 2.

System 4

Solar energy can be used directly as the primary energy source to produce electricity (by thermal or photovoltaic means) which is used to produce hydrogen by water electrolysis. Hydrogen then becomes the energy carrier via underground pipelines for dispersed utilization of fuel cells at urban load centers as in System 2.

Potential Environmental Burden of Fuel Cells

System 1. - Integral Reformer (Natural Gas, Oil). Reduced waste heat rejection is possible with System 1 because of higher thermal efficiency of fuel cells compared to conventional energy converters. As a first approximation, the improvement in fuel utilization for fuel cells can be estimated from efficiency versus power output shown below.

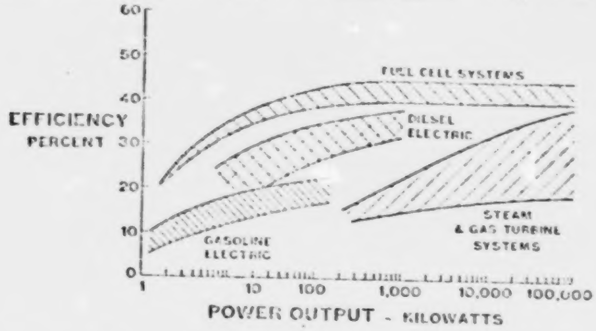


FIGURE W-1. POWER SYSTEM EFFICIENCY COMPARISON(W-2)

Fuel cells have reduced atmospheric pollution emissions compared to most combustion systems. Fuel cells with integral reformers have integral scrubbers to remove sulfur dioxides. Principal source of atmospheric contaminants is the fuel burned to supply heat to reformer. Significant reduction of atmospheric pollutants is achieved with fuel cells compared to gas-fired central station as shown in the following tabulation:

	Pounds per Thousand kwhr	
	Gas-Fired Central Station	Fuel Cells(a)
Sulfur Dioxide	0.3	0.0003
Nitrogen Oxides	4	0.24
Hydrocarbons	2.8	0.23
Particulates	0.1	0.00003

(a) Based on data from experimental fuel cells
Source: Reference W-2

Since fuel cells do not require a heat sink as do Carnot cycle systems, the heat load represented by the inefficiency is added to the atmosphere (air cooling used) rather than water, and heat dissipation is as dispersed as the fuel cell power plants. Some heat can be beneficially used at residential/commercial sites.

The use of dispersed fuel cells results in a proportionate reduction of overhead electrical transmission requirements with improvement of land use and esthetic benefit.

The use of fuel cells on pipeline gas can be arranged to provide energy storage for peak use periods and reduce requirements for other peak load systems such as: conventional fossil fueled peaking systems, use of marginal fossil-fueled base-load systems of high pollution level, and pumped-hydro storage.

Future use of coal gasification to provide a (high Btu) synthetic gas for pipeline distribution wil add to the atmospheric pollution load at the coal gasification site while removing sulfur and reducing the sulfur oxide atmospheric pollution at the fuel cell site.

System 2. Pipeline Hydrogen (From Coal). The use of pipeline hydrogen will eliminate atmospheric pollution load at fuel cell sites compared to System 1. Coal gasification will provide some atmospheric pollutants but probably no significant NO_x if carried out at low enough temperature. Sulfur and other atmospheric contaminant control will be greatly reduced by economy of large-scale pollution control and will only be produced at sites remote from urban areas.

System 3. Nuclear Energy (Hydrogen by Electrolysis). Local atmospheric pollution will be completely eliminated, compared to Systems 1 and 2, by use of electrolysis of water as the source of hydrogen (rather than coal).

There will be an increased thermal pollution load at the nuclear/electric generating site due to the inefficiency of water electrolysis and greater need for electric power. Present state-of-the-art water electrolysis is less than 50 percent efficient. Advanced water electrolysis cells are expected to increase the efficiency to 75 percent, and long-range goals would be an efficiency of 80 to 90 percent. It should be noted that theoretical electrical energy (voltage) efficiencies of water electrolysis and fuel cell are 100 percent. Theoretical thermal efficiency of hydrogen production by electrolysis is about 120 percent but corresponding theoretical thermal efficiency of H_2/O_2 fuel cell about 82 percent.

With hydrogen generation using nuclear/electric source and pipeline distribution of hydrogen, remote siting of the nuclear plant is possible. Energy distribution by pipeline hydrogen is more economical than underground electrical distribution in general and more economical than high voltage overhead electrical transmission for distance greater than 400 miles.

System 4. Solar Energy (Hydrogen by Electrolysis). An inefficiency in hydrogen generation by water electrolysis using a solar/electric energy source does not add materially to the thermal burden of the earth.

This is an ideal system in that there is no atmospheric pollution, no thermal pollution, and no overhead transmission lines. Hydrogen provides a means of underground energy storage for peak power demand and would eliminate the need for pumped hydro sites.

Estimated Funding Effort and Requirements

Estimated funding requirements for research and development related to fuel cells are given in Table W-2.

TABLE W-2. ESTIMATED FUNDING EFFORT AND REQUIREMENTS RELATED TO FUEL CELLS (Millions of Dollars)

System	Millions of Dollars Expenditures to Date, 1972	Expenditure for Each 5-Year Period Through 1975	1980	1985	1990	Beyond 1990
1	50(a)	26(b)	15(b)	10(b)	?	?
2(c)	50(a)	3(d)	5(d)	25(d)	25(d)	?
3 and 4(c)	2	3	5(e)	9(e)	12(e)	?

(a) This is estimated past expenditures on TARGET program and related fuel cell research. Does not include ~$250,000,000 of prior government R&D

related to developing Apollo and Gemini fuel cells.

(b) Estimated funding by electric utilities to evaluate fuel cells for substation use.

(c) System 2 costs do not include funding on coal gasification or production of hydrogen from coal.

(d) Estimated expenditure to develop urban fuel cell concept and related hydrogen transmission technology, and to explore residential d-c usage and waste heat utilization.

(e) Estimated expenditure to develop water electrolysis as an economic alternative to hydrogen production from fossil fuels by use of nuclear and/or solar energy.

Magnitude of Energy That Can Be Developed

For System 1, the magnitude of the energy that can be developed using a fuel cell system is limited by the present availability of natural gas that can be directed from other uses to this form of electric energy production. The use of low sulfur liquid fuels presents a similar short term supply situation.

Successful development of economic coal gasification would permit a high percentage of electric needs to be satisfied by fuel cells using either synthetic methane or hydrogen for System 2.

Systems 3 and 4 are predicated on reduction in cost of electric power by fission, fusion, or solar means to near or less than the cost of hydrogen produced from coal. All electric energy needs beyond the year 2000 could ultimately be provided by a hydrogen distribution system with dispersed urban fuel cells. Also, with low cost hydrogen, residential, commercial, and industrial thermal energy requirements could be satisfied by pipeline hydrogen as well as the needs of the chemical and metallurgical industries for hydrogen (i.e., ammonia and iron ore reduction).

Solar Energy Systems

Several types of systems for converting solar energy to electrical energy are theoretically feasible for large-scale central power station use. These will be discussed below. It should be kept in mind that residential heating and cooling consumes nearly one-fourth of the fuel required for the United States and that solar energy could best provide a substantial portion of these requirements "on site" to reduce the overall central power station requirements.(W-3,W-4)

Figure W-2 is a diagram showing various solar energy conversion modes presently available with expected efficiencies indicated.(W-5) Not shown on

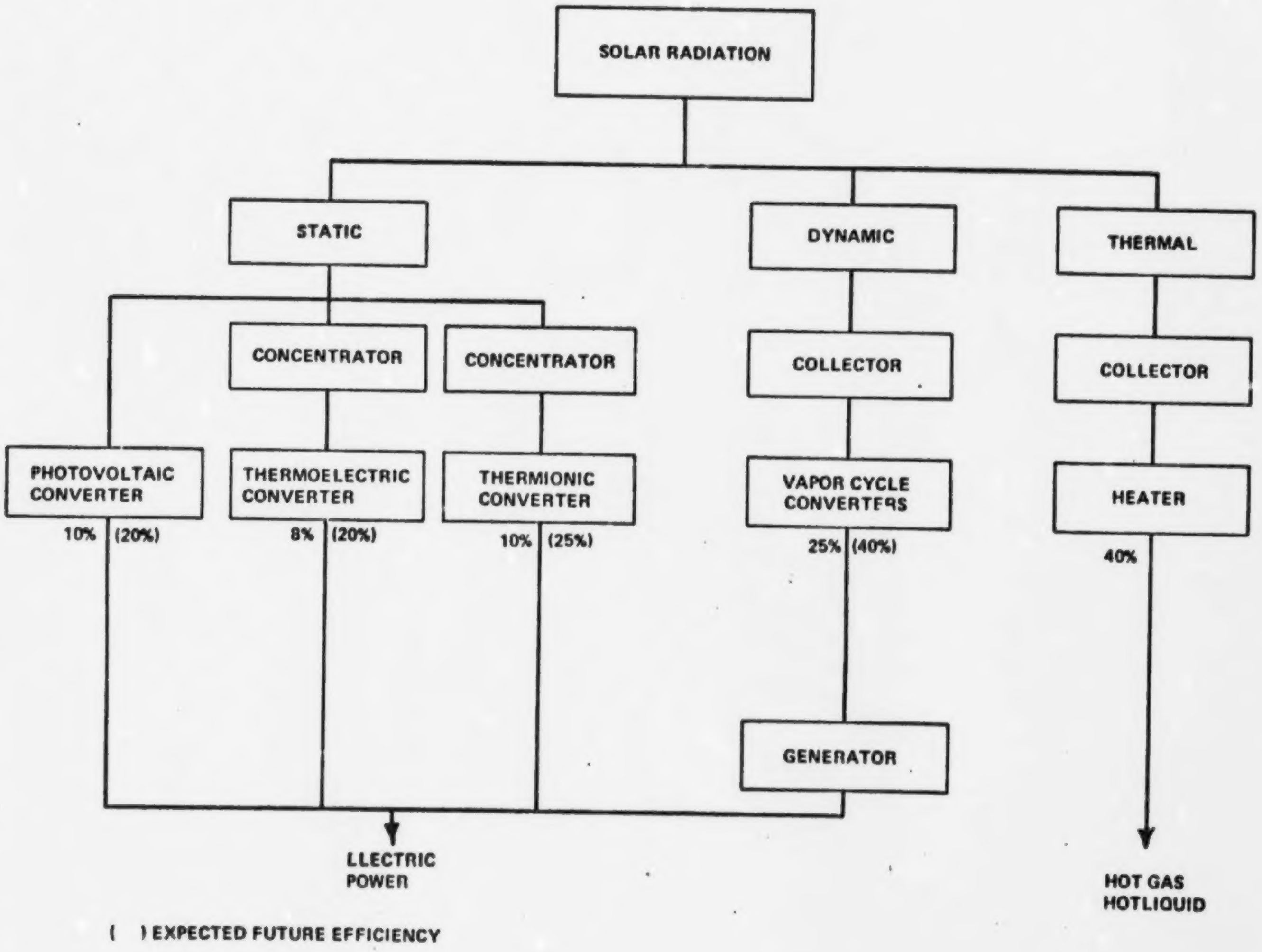

SOLAR RADIATION
STATIC
DYNAMIC
THERMAL
CONCENTRATOR
CONCENTRATOR
COLLECTOR
COLLECTOR
PHOTOVOLTAIC CONVERTER
THERMOELECTRIC CONVERTER
THERMIONIC CONVERTER
VAPOR CYCLE CONVERTERS
HEATER
10% (20%)
8% (20%)
10% (25%)
25% (40%)
40%
GENERATOR
LLECTRIC POWER
HOT GAS HOTLIQUID
( ) EXPECTED FUTURE EFFICIENCY

FIGURE W-2. SOLAR ENERGY CONVERSION MODES this figure is the simple scheme that has existed since the creation of the world, which is using solar energy to grow trees to provide fuel for conventional power plants.(W-3)

If one considers the average daily radiation for the continental United States, it is realized that the energy level is quite low. Therefore, large collector areas are required to capture enough energy to power a large electrical generating station. For example, the average daily amount of total solar radiation (direct and diffuse) incident on a horizontal surface in the continental United States is about 600 Langley's/day (2,210 Btu/ft^2-day, or 27 watts/ft^2) in June and decreases to about 200 Langley's/day (740 Btu/ft^2-day, or 9 watts/ft^2) in December.(W-6) Thus, if a horizontal flat plate collector and associated equipment were 100 percent efficient in converting this solar energy to electricity, a 1,000 MW station would require a collector area of approximately 1.3 square miles in June and 4.0 square miles in December.

Focusing collectors which track the sun will level out this yearly variation in radiation intensity. The direct-normal intensity at 40 degrees north latitude will always average about 290 Btu/hr-ft^2 at noon on clear days, but the hours of sunlight will vary from about 15 hours on June 21 to only about 9 hours on December 21.(W-7) Therefore, the total flux received on a surface kept normal to the sunlight will vary from about 3,200 Btu/ft^2-day (39 watts/ft^2) in June to about 2,000 Btu/ft^2-day (24 watts/ft^2) in December. Consequently, a 1,000 MW generating station, using sunlight-tracking collectors and operating at 100 percent conversion efficiency, would require a collector area of approximately 1.3 square miles in June and 4.0 square miles in December.

Another consideration influencing the design of solar collectors is the maximum operating temperature required by the energy conversion system. The following tabulation outlines the basic requirements.(W-8) The use of surface coatings to increase the ratio of solar energy absorbed to the thermal radiation emitted will tend to increase the maximum temperatures achieved for each type of collector and increase the collection efficiency.

Maximum Operating Temperature	Type Collector
Below 100 C (212 F)	Stationary, nonfocusing
100 C (212 F) to 200 C (392 F)	Stationary, focusing, low concentration
Above 200 C (392 F)	Tracking, focusing

Considering the overall technological and economical feasibility of the various solar energy conversion systems discussed herein, they are rated below in descending order of priority in terms of energy capability:

1. Residential heating, cooling, and hot water

2. Rankine cycle

3. Solar cells.

4. Stirling engines.

5. Satellite system.

Residential Heating and Cooling

It has been reported that about 25 percent of the total energy consumption in the United States is for the heating and cooling of buildings, and that 22 percent of the total is consumed for residential dwellings.(W-3) Of the energy required for homes, an average all-electric home in the United States consumes about 100 million Btu's (29,300 kwhr) per year, of which 45 percent is for heating, 15 percent for cooling, and 25 percent for hot water.(W-9) Thus, if solar energy were used to provide for the residential heating, cooling, and hot water needs, this would represent a total energy savings of almost 20 percent.

Solar energy is already well distributed, and its quantity is quite well matched to residential needs for comfort heating, cooling, and hot water. For example, the average total amount of solar radiation (direct and diffuse) falling on 1,000 square feet of horizontal surface in the United States is approximately 550 million Btu's per year. However, energy storage requirements, and winter and summer needs would have to be considered carefully for each locality, we well as optimum sloping of the roof collectors for year-round use.

Perhaps it may never be feasible to provide for 100 percent of residential heating and cooling by means of on-site collection and storage of solar energy. One analysis, which considered only solar heating, concluded that it is most economical to design for only about 50 percent of the total requirements in most areas of the United States.(W-10)

Environmental Factors. The successful development of "on-site" solar heating and cooling for residential dwellings could reduce the environmental pollution caused by central power plants by as much as 10 to 20 percent. Since solar energy is already well distributed, the use of its energy when and where it is received will have the least overall detrimental effect on the surrounding environs.

Capital Costs. Home heating with solar energy is estimated to be cost competitive with electric resistance heating at \$0.02/kwhr (\$5.85/10^6 Btu) for many parts of the United States.(W-3) However, solar collector and heat storage systems have not yet been developed to the necessary dependability and economy required for widespread public use.

R&D Expenditures. A complete 10-year program of research and development for solar heating and cooling of dwellings has been formulated.(W-3) This calls for a total expenditure of between \$10 to \$20 million over the 10-year period.

Solar Powered Rankine Cycle

This type of system usually consists of solar concentrators to focus the sunlight onto heat collector tubes. This heat is then transferred by means of a circulating fluid to a heat storage unit. The stored heat energy is used as needed to produce steam for a conventional steam turbine generating plant.

At least two such designs are currently under study.(W-4) Aden Meinel at the University of Arizona is designing a collector using Fresnel lenses to concentrate the solar flux 10 times and focus them onto stainless steel or glass ceramic pipes. These pipes would have selective coatings to increase the relative absorptance of the solar energy, and would be enclosed in evacuated glass tubes to further reduce heat losses. Nitrogen gas would be circulated through the pipes and transfer the heat to a central heat storage system consisting of an eutectic mixture of molten salts. This stored heat would then be used to produce steam for a conventional turbine as required.

The second study, headed by Ernst Eckert at the University of Minnesota and Roger Schmidt at Minneapolis-Honeywell, Inc., utilizes a parabolic reflector to concentrate the sunlight onto a heat pipe. Again, selective coatings and evacuated chambers would be used to increase the collection efficiency. Each heat pipe would have a separate heat storage unit and the steam generated would be returned to the turbine-generator.

Work on solar-powered vapor turbines has been conducted by H. Tabor, and a 600-watt experimental unit has been built using dichlorobenzene as a working fluid.(W-8,W-11)

Another type of solar-powered Rankine cycle would use the thermal gradients in the oceans to operate a turbine-generator unit.(W-12,W-13) However, the overall temperature difference available is quite low (about 40 F) and, consequently, the overall thermal efficiency of the plant will be very low, probably less than 5 percent. Therefore, very large heat exchanger surface areas are required. If these heat exchangers can be designed for low cost by proper design, and if efficient components are developed, then this scheme may prove useful for some coastal regions where favorable temperature gradients exist in the ocean.

Environmental Factors. Although solar energy has probably the fewest potential environmental problems associated with its use of any of the major sources of energy, some problems do exist. Collecting surfaces absorb more sunlight than the earth does, and while this is not likely to alter the local thermal balance in household or other small-scale use, the large expanse of collecting surface required for a central power plant might. For example, at an estimated maximum overall efficiency of 20 percent, a 1,000 MW solar-powered generating station would require a collector surface area of approximately 12 square miles, assuming an average daily intensity of 15 watts per square foot on a year-round basis. However, a solar plant may have to be sized for winter radiation conditions, which could increase the collector size by 50 percent.

Thermal pollution will also be a problem if water-cooled steam condensers are used--even more so than with nuclear power plants because solar installations are expected to have even lower thermal efficiencies. If waste heat is returned to the atmosphere, it could help to restore the local thermal balance. The effects of these changes in the thermal balance would depend on the local meteorological conditions, but are expected to be small.

A floating power plant operating on the thermal gradients in the ocean would have almost no detrimental environmental impact. It may present some hazard to ships, and it would have to be designed to remain operational during severe storm conditions.

Capital Costs. It is estimated that the cost of solar-thermal plants will be not more than two or three times what fossil-fueled plants (less than $500/kw) or nuclear-generating plants cost now, and that rising fuel costs will eventually tip the balance in favor of solar-thermal plants whose fuel is "free".(W-4) Before accurate estimates of costs can be made, however, more detailed engineering studies and some additional research are necessary. But Meinel believes that full-scale solar-thermal power plants could be built as early as 1985 with an adequate research effort. Other estimates are somewhat less optimistic, but a group of western utility companies is considering the development of a small solar-powered facility that could serve as a prototype for peak load applications.

The capital costs for a floating power plant were estimated by J. H. Anderson, Jr.(W-13) to be only $166/kw, and the total cost of electricity to be only $0.00285/kwhr. However, considerable research and development work needs to be done on various components of this system to verify these estimates.

Solar Cells

Arrays of solar cells have been developed for use in space applications to generate electrical energy directly from sunlight. For terrestrial applications their output is reduced approximately tenfold because of the lower radiation intensities and the diurnal variations.(W-5) In addition, storage of the electrical energy would be required, as well as conversion from d-c to a-c power.

Environmental Factors. Thermal pollution is essentially zero for solar cell arrays, as the sunlight is converted directly to electrical energy. However, large land areas will be required because of the low conversion efficiencies (e.g., 6 to 8 percent presently, perhaps increasing to 20 percent eventually). The estimated direct current output for terrestrial use is 1 watt per square foot (W-5) so that a 1,000 MW generating station would require approximately 36 square miles of land area, or about 23,000 acres. There certainly will be an environmental impact of such a "solar farm" due to thermal updrafts such as now exist over cities, and because the land itself becomes unproductive.

Capital Costs. The present cost of small solar arrays (10 to 100 kw) using silicon cells is about $300,000 per kw. Projected estimates for array sizes of 1 to 1,000 MW are $50,000 per kw and for 1,000 to 10,000 MW sizes are $5,000 per kw.(W-5) Some very recent estimates of costs of thin-film CdS cells, once fully developed for low cost mass production, indicate the costs may ultimately be reduced to less than $1,000/kw. However, the efficiency of these cells may be less than 6 percent.

R&D Expenditures. More than $10 million have been expended thus far in developing silicon solar cells for space applications. To develop solar cell arrays sufficiently to supply a significant portion of the electrical energy requirements of the United States by the year 2000, an expenditure approaching $300 million per year for six years may be required.(W-5)

Table W-3 presents another projected research costs program for developing low-cost solar arrays as a first basic step toward achieving large-scale use of solar cells.(W-14)

Solar-Powered Stirling Engines

Focusing parabolic solar collectors have been used to power small Stirling hot-air engines(W-15,W-16,W-17) and these could be mass produced for large-scale generation of electrical power.(W-18) A parabolic solar collector 6 feet in diameter could generate approximately 200 watts using a Stirling engine, which is an overall energy conversion efficiency of about 8 percent at peak radiation intensities.

Environmental Factors. Again, a large area of land would be required for a large-scale generating plant because of the low conversion efficiency. If many small individual units were used, then somewhat more land would be required because of space needed around each unit. The land area required would probably match or exceed that listed for solar cells, namely 36 square miles for a 1,000 MW station.

The thermal pollution problems would be similar to those discussed for the Rankine Cycle systems, as waste heat must be dissipated either to the ambient air or another heat sink.

Capital Costs. It has been estimated that solar powered Stirling engines could produce electricity for about $500 per kw while the sun is shining, which is about one-third of the total time.(W-18) These costs were divided up as follows: $1 per square foot for the 6 foot diameter prarbolic collector, and $15 each for the 200-watt Stirling engines which could be mass-produced. The remainder of the costs would involve tracking systems, maintenance, etc.

R&D Expenditures. Solar-powered Stirling engines are a proven concept in principle, but some problems with seals and with lubricants over long

TABLE W-3. PROJECTED PROGRAM COSTS AND SCHEDULE FOR THREE OPTIONS

OPTION / RESOURCES / PHASE	OPTION A "ROOFTOP"		OPTION B "SOLAR FARM"		OPTION C "SATELLITE"	
	COST $M	SCHEDULE	COST $M	SCHEDULE	COST $M	SCHEDULE
PRE PHASE A Preliminary design & feasibility assessment. Conceptual design of alternative approaches. Identification of critical system parameters.	None	None	1	1.5	3	1.5 1-1-75
Phase A Establish system feasibility & most desirable approaches. Assessment of technical advances needed. Gross cost and schedule projection.	None	None	3	1.5	20	1.5 7-1-76
Phase B Preliminary design of preferred system. Detail assessment of requirements including resource, manufacturing and test requirements. Preliminary system cost & schedule projection. All pre-commitment objectives completed.	60	3	60	3	60	3 7-1-79
Phase C Final definition: Freezing of concepts, approaches, designs, schedules, and costs of program. Intensive development of operational systems. Initiation of testing.	300	3	300	3	2,100	3 7-1-82
Phase D Final development & operational phase. Operational system components developed. Demonstration hardware fabricated and extensively tested. Prototype built. Commercial readiness achieved & competitive position ascertained.	1,000	5	1,000	5	8,000	8 7-1-90
* TOTAL	1,360	11	1,364	14	10,183	17 Yrs.

* From Research Paper No. 135, Heliotek Div. of Textron, Inc. "Solar Energy R & D Policy Assessment" by E. L. Ralph

time periods are yet to be solved. Also, optimization studies would be needed before arriving at a final design for large-scale power plants. An expenditure of several million dollars per year for 10 years would probably be required to develop such a system.

Satellite Solar Collection System

This scheme involves the putting of at least two giant satellite systems into synchronous orbits with large arrays of solar cells to intercept the solar energy. This energy will then be converted to microwave radiation, and beamed to earth receivers where it could be reconverted to electrical energy.(W-19,W-20)

One such satellite solar power station designed to produce 10,000 MW would have a solar collector array area of 25 square miles, a microwave transmitting antenna area of 1 square mile, and an earth-based receiving antenna area of 36 square miles.(W-20)

Environmental Factors. The major impact of this arrangement would be the possible hazard of the energy beam transmitted to earth. The intensities may be high enough to cause some damage to objects or living beings. Safety measures would have to be devised to prevent entry into the beam.

Capital Costs. Cost estimates for this system have not been published, but they will undoubtedly be very high. The costs given for solar cells in another section will apply for the solar collector array. In addition, there would be the cost of improving the technology for the microwave transmitting and receiving equipment, as well as putting all of the equipment into a synchronous orbit.

R&D Expenditures. It has been suggested that the United States spend $500 million in the next 10 years to study the feasibility of a satellite solar energy system.(W-21)

R&D costs for developing cheaper solar cells to be used in satellite systems are given in the solar cells section.

Other Systems

Other solar energy conversion systems include thermoelectric and thermionic converters, and closed-cycle Brayton systems.

Thermoelectric and thermionic systems are described elsewhere in this report, and solar concentrators would be used to provide the high surface temperatures required. However, as yet, the overall efficiencies and life expectancies are low, and the material costs are high.

A closed-cycle Brayton (gas turbine) system could be operated using solar collectors as a heat source, but its overall efficiency would be lower than a comparable Rankine cycle because a gas compressor would be required in addition to a turbine expander. Also, larger heat exchangers would be needed to compensate for lower heat transfer coefficients on the gas side, as opposed to higher condensing and evaporating coefficients for Rankine cycles.

Heat Pumps

The heat pump is a refrigeration system which can be used to provide both heating and cooling. Heat pumps are also referred to as reverse-cycle refrigeration, although this is somewhat of a misnomer since the basic refrigeration cycle is still used. Heat pumps have primarily found application in the comfort control of residential homes, although some heat pumps have been installed in larger commercial buildings.

Although the heat pump could theoretically utilize any thermodynamic cycle that produces refrigeration, economic considerations dictate that the vapor compressions cycle be used. The evaporator draws heat from a low temperature source (the outdoor environment in the heating season and the indoor environment in the cooling season) and this heat is rejected, along with the heat of compression of the fluid, to the higher temperature sink. During the summer, heat is "pumped" to the outdoors and in the winter it is "pumped" indoors.

The most common measure of performance of the heat pump is the coefficient of performance (C.O.P.), which is the ratio of the "useful" heat moved to the quantity of energy required to operate the system. In the winter season the useful heat is the energy rejected by the condenser. The useful heat in the summer is the energy absorbed by the evaporator. Table W-4 lists typical values of C.O.P.'s obtainable with various heat sources and sinks.

TABLE W-4. COEFFICIENTS OF PERFORMANCE FOR ELECTRICALLY DRIVEN HEAT PUMPS WITH VARIOUS SOURCES AND SINKS

Source/Sink	C.O.P. Heating	C.O.P. Cooling
Air	2.5	3.0
Water	5.0	4.0
Earth	3.0	3.0

Environmental Burden

The widespread use of heat pumps for residential and commercial space heating and cooling could substantially reduce the local air pollution caused by the more conventional fossil-fuel fired heating systems since the operation of these systems is essentially pollution free. The electrical energy that is required is normally generated at a central power plant where more sophisticated pollution control devices are available.

Heat pump systems can also conserve significant amounts of energy during the heating season since a portion of the energy released to the heated space is energy which would not normally be tapped. This can be illustrated by considering the overall efficiency of utilization of fuel for heating a home. For a typical gas- or oil-fired furnace, the efficiency can be considered to be about 75 percent. For the case of the central power station operating at 40 percent efficiency in conjunction with a air-to-air heat pump operating with a C.O.P. of 2.5, the overall efficiency can be calculated as 40 percent times 2.5 or 100 percent. This represents a 33 percent increase over typical residential gas- or oil-fired furnaces. Thus, the overall efficiency of utilization of the fuel is improved considerably. Supplemental resistance heating is sometimes used in conjunction with residential heat pumps during the heating season. Any extensive use of this supplemental heating system lowers the overall energy efficiency and adversely accentuates the demand imposed on central stations.

The environmental impact of using air as the heat source/sink is quite small, but if water or earth is used as the source, the impact on the environment must be assessed more carefully. If well water is used, the water must be disposed of in a suitable manner, which usually means drilling another well to return the heated or cooled water to the ground. For earth heat sources, the changes brought about by continuously withdrawing or adding heat from or to a finite mass of earth must be assessed.

Capital Costs

A three-ton heat pump unit installed in a typical residential home (1500 square feet) would cost about $1800. Operating costs of heating a home with an electrically driven heat pump run appreciably higher than the same house heated by natural gas, but about half as much as the same house heated by electrical resistance heating.(W-9)

R&D Expenditures

Heat pump technology is well developed at the present time and commercially available units have been on the market for some time. These units have not found wide acceptance in the northern part of the country; however, due to the fact that the C.O.P. of the air-source heat pump drops off at lower ambient temperatures. The use of solar energy as a heat source has received some attention. If suitable techniques for utilizing this energy could be developed, the use of heat pumps would undoubtedly become more widespread.

Geothermal Power

System Description and Status

Geothermal power is the utilization of heat from the earth's interior to produce electrical power and serve other useful purposes.

The present world utilization of energy from geothermal sources is about 1200 MW. While this represents an exceedingly small percentage of total world and United States usage (about 0.1 percent in each case), geothermal power can be significant in its local utilization, e.g., California, Italy, and New Zealand. The relative anticipated growth of geothermal power is estimated to be 4000 MW by 1980. Approximately one-third of this growth will occur in California, of which the majority will be in the Geysers region.

In a recent article on geothermal energy Rex(W-22) estimated that by concerted exploration and development the proven geothermal resource could be between 100,000 MW and 1,000,000 MW in the year 2000. Another(W-23) estimate of the geothermal resource is 132,000 MW in 1985 and 395,000 MW in 2000. By comparison, the present power capacity of the United States is a little over 300,000 MW.

At the present time, any discussion of geothermal power must keep in mind the distinctions between utilization, resource, and resource potential. Thus, while present utilization is small (about 1200 MW) and proven resources only a few times that, the known resource potential is significantly larger. The utilization of this resource potential, both in the United States and the world, will depend on technological development as well as political and economic factors. Large-scale utilization of geothermal power is unproven, but the tremendous resource potential as well as advantages in economics, environmental pollution, and nondepletion make it a highly attractive source for future energy needs.

Description of the Geothermal Energy System

In certain limited locations groundwater through pores and fissures in the rock comes in contact with hot material rising from the earth's interior. This results in locally large natural underground reservoirs of steam and/or hot water which can be tapped by drilling to drive turbines in power plants and provide space heating in buildings and greenhouses. These geothermal energy sources can be described by

1. Natural steam systems.

    (a) Dry steam fields which have a relatively high energy content

(b) Wet steam fields which produce a mixture of hot water and steam and have a lower energy content

2. Hot water fields which have a low energy content.

Fields of the first type can be used directly to produce electrical energy from steam. It has been proposed that a heat exchanger using a low boiling fluid such as freon be used to produce electricity in the second type. The economics of this system have not been demonstrated and may be unfavorable. This hot water source of energy can also be used for local heating.

All types of geothermal resources are currently being used as sources of energy. Dry steam fields are generating about 700 MW of power at Larderello, Italy, and the Geysers, California. The Wairakei, New Zealand, field produces about 200 MW of power from wet steam. At Cerro Prieto, in Maja, California, a wet steam field is expected to start producing 75 MW in January, 1973. Geothermal hot water is used for residential heating in Oregon, Idaho, Iceland, and Siberia.

The identification of these geothermal resources has been based on surface manifestations, e.g., hot springs and geysers. This is quite similar to the early identification of oil reservoirs. As resource identification techniques improve the extent and magnitude of the hot water or steam geothermal resources are expected to increase significantly. This could result in increased planning for the utilization of geothermal energy by the nations' utilities companies.

Another, possibly more extensive, source of geothermal power is dry, hot rock which does not have water associated with it. Means of tapping this geothermal potential have not proved technically feasible, but field experiments to test the concept have begun. Should this concept be proven feasible, geothermal power could be used extensively.

A possible third geothermal energy source exists; the so-called geopressure regions. Deep sedimentary basins filled with sand and clay or shale of a young geologic age (such as exist off the U.S. Gulf Coast) are generally undercompacted to depths of several kilometers. The resultant pores are filled with fluid. However, because of the undercompaction these interstitial or pore fluids are at pressures between the hydrostatic and lithostatic head. These regions are said to be geopressurized.

The search for oil and gas throughout the world has discovered many geopressure reservoirs. These have not been tapped for geothermal heat. The location of many of them occurs in regions different from the steam and hot water sources so that the geopressure regions could potentially expand the geothermal resource potential significantly.

Natural Steam Systems

As described above, the natural steam systems can be divided into dry and wet sources. The means of using dry geothermal steam to generate electric power is straightforward and is like the similar portion of a conventional power plant except that the operating pressures and temperatures are considerably lower. This requires turbines of special design.

Steam is available at the well head and is piped directly to the power plant. The steam requires no special treatment other than filtering out rock particles. The steam is expanded through a turbine, thereby turning a conventional electric generator. The steam is discharged through a condenser and converted into water. Because the dry steam contains low impurities, the majority of the water can be evaporated in cooling towers. A small amount of water containing concentrated impurities must be disposed of by surface means or by reinjection into the ground.

In the case of wet steam sources steam must be separated from the water. The hot water rising in the geothermal wells flashes to a mixture of steam and water as the pressure decreases. The steam and water are separated outside the well head; the steam follows a cycle similar to that described for the dry source. The water must be discharged into the environment or reinjected into the ground. Because the water makes up two-thirds to four-fifths the fluid removed from the ground and often carries a large dissolved mineral content, it poses serious environmental problems. Geopressure systems may provide water hot enough to flash into steam.

Hot Water Systems

In this proposed system, the hot water is pumped through a heat exchanger. Part of the energy would be transferred to a low boiling working fluid such as freon and isobutane. The geothermal water, now cooled, can be returned to the earth or disposed of in some other way. The heat exchanger acts as a boiler for the working fluid which is evaporated and passed through a power turbine to generate electricity. The fluid is then condensed and the working fluid is pumped to high pressure and again run through the heat exchanger. This is exactly the fashion in which a conventional fossil-fired steam boiler or a nuclear power plant operates. This type of system is also usable for a pumped wet steam energy source.

Dry Rock Systems

The proposed dry rock system would utilize the energy from hot-dry rocks close to the earth's surface. These are believed to be much more widespread than the steam and hot water sources. The approach would be to drill a well deep into the hot rock. This rock is then fractured by some means in order to provide a large volume whereby a working fluid can be injected and heated. It has been proposed to fracture the rock by conventional hydrofracturing techniques(W-24) or by nuclear explosives.(W-25) Both approaches are unproven and speculative.

The working fluid is injected into one drill hole and removed from another drill hole spaced a considerable distance away. Depending on the site location, temperature and pressure of the working fluid, and availability of local water, the power generating part of the cycle can be any of the above discussed options or a suitable combination of them.

Potential Environmental Burden

Impact on the Land.

Land Use. The most obvious environmental effects associated with geothermal power is the intrusion of an industrial operation into a usually nonindustrial area. For example. a geothermal well is drilled in the same fashion as an oil well. Problems include noise, the appearance of drill rigs, access roadways, drill platform pads, drill cuttings, and drill fluids. After the well is drilled it must be tested. This results in noise, wastewater, and probable air pollution. These are temporary effects and can be minimized by careful planning. Once drilled and in production the actual geothermal well can be made unobtrusive and, hopefully, will offer no severe environmental problems.

Because the working fluid cannot be moved more than a mile without serious heat loss, the generating plant must be located near the wells, thereby localizing the total environmental impact to the site where the geothermal field is located. The fluid is transported to the generating plant by insulated pipes; these pipes are costly to run below ground; therefore, the tendency will be to run them above ground. Such pipes are visible environmental disturbances. The power and water plants are conventional with noticeable noise level and cooling towers. The cooling towers are large and evaporate steam into the atmosphere. Thus, a residential usage would generally be incompatible with a geothermal field.

Using the Geysers field as an example, present well-flow information indicates that sufficient steam can be produced for a 1000 MW plant from an area between 4 and 8 square miles. However, since only a small part of the whole field is required for the wells, pipelines, and generating plants, the rest can be utilized for other purposes. For example, at the Larderello field in Italy, where geothermal steam has been utilized for power production for nearly 60 years, an intensive agricultural industry is carried on within the steam field, and many vineyards and orchards are interspersed among the pipelines and wells.(W-26)

The uses of the land associated with a geothermal field must be site dependent, e.g., topography, climate, ground cover, etc. Many of the known geothermal resource areas in the United States occur in places that are valued for their scenic beauty. Thus, the industrial character of the geothermal area will notably affect the scenic values. The evaluation of the environmental impact of a geothermal field on the land seems to be dependent on the viewpoint of the observer.(W-26,W-27)

However, there seems to be general agreement that the environmental impact of a geothermal field is less than that of a correspondingly sized nuclear or fossil fuel plant if one considers the total impact of the mining, milling, fabrication, transportation, plant facilities, fuel storage, and waste.

Subsidence. When large quantities of fluids are removed from an underground reservoir, the land surface may sink. The consequences are sometimes disastrous as was the case with the Wilmington, California, oil field. Subsidence can occur when the reservoir rock is very porous; removal of the fluid can cause the rock grains to fail or compact. If the reservoir consists of fractured rock, subsidence is unlikely. The ideal approach to utilization of the geothermal resource would be to remove fluid at or near its recharge rate, thus conserving the resource. This approach would probably eliminate the subsidence problem. Since subsidence could have serious environmental effects, but is not common, future geothermal developments will have to be monitored for this effect.

Seismic. Experience near Denver, Colorado, has indicated that seismic activity can be stimulated by the injection of water deep underground. The seismic effects of water withdrawal and reinjection in geothermal fields will be peculiar to the particular area, and cannot be stated to be or not to be a problem at this time. There are suggestions that the induced microseismicity relieves strain on faults and tends to prevent major earthquakes.(W-28) However, because this seismic activity is not predictable at the present time, it should be carefully monitored to indicate possible hazards.

The seismic effects associated with nuclear stimulation of a dry geothermal resource is a different situation. While these effects are dependent on the size of the device, depth of burial, geological structure, and location, it is highly unlikely that device sizes larger than 100 kilotons will be seismically acceptable for use at most locations.

Pollution Factors.

Thermal. In order for a thermal electric power plant to operate at maximum efficiency, the steam must be condensed after passing through the turbine. The amount of cold water required to condense the steam in thermal plants is large. An efficient 1,000 MW fossil fuel plant using cooling towers evaporates 15 to 25 million gallons of water a day, whereas a nuclear power plant, because of its lower thermal efficiency, evaporates about 50 percent more water. However, geothermal plants that utilize dry steam do not require additional water for cooling. The natural steam, after passing through the turbine, is condensed within the circulating cooling water and thus provides additional water to the cooling towers. Thus, the dry steam geothermal system should pose little or no problem of thermal pollution to local water sources.

When the utilization of the geothermal resource is of the closed-cycle design, such as in the pressurized wet steam source or in the proposed hot-dry rock source, the heat is transferred to a working fluid through a heat exchanger. The working fluid must be cooled and condensed. This can be accomplished by using cooling water or air. The latter approach--using forced-draft, air-cooled condensers--has been specified for the hot dry rock source(W-24) in order to avoid thermal pollution of water bodies and to have freedom in siting. The authors state that "the economics for this type of geothermal power are so favorable...that the additional...generating costs associated with the air-cooling equipment can easily be absorbed".

Wastewater. The experience at the Geysers seems to indicate that wastewater is not a problem for dry steam sources. This results from the fact that the underground fractional distillation of steam leaves the majority of the dissolved minerals behind.

However, the surplus water remaining after evaporation in the cooling towers contains trace chemicals which preclude its discharge into the local streams. The water would require further treatment, or as at the Geysers, must be reinjected into the ground in deep wells. This amounts to about 20 percent of the condensate. For 100 MW of generating capacity, this amounts to over 1 million gallons/day. One large injection well can accommodate this flow. Thus, a 1,000 MW plant might require several large injection wells.

A more difficult problem arises when the geothermal wells produce hot water, or a steam/water mixture. In these cases the surplus water must be disposed. In some instances, when these wastes are high in mineral content, they cannot be discharged into surface waters. Unless very well mixed, even ocean discharge could lead to severe local effects if the plant waste differed substantially from ocean water.

At Cerro Prieto, in Mexico, the waters contain about 2 percent salt (ocean water contains 3.3 percent salts). For a geothermal electric plant located here and of 1,000 MW size, it has been calculated that saltwater would be produced at a rate of approximately 150 million gallons/day, or over 150,000 acre-foot annually. For a 2 percent brine solution, 12,000 tons/day of salts would result if the water was evaporated away. For the 20 percent brine found in the Salton Sea area, 120,000 tons/day of salt would result. This poses a monumental solid disposal problem, and constitutes a real environmental danger.(W-27) Thus, the disposal of brines is a serious environmental problem.

The method that appears most promising is disposal into injection wells. An injection well is drilled to a depth where a porous formation will accept the water. To avoid contamination of ground waters, these depths may involve several thousand feet. After overcoming original well-head pressure, it is often found that the water can be literally poured down the hole. This method has found wide use for disposal of oil well brines and industrial wastes. One must take care to avoid aquifers that connect to areas where the waste will do harm, e.g., sources of agricultural or potable water. This is not thought to be a problem in geothermal areas. Should this proposed technique prove successful a major environmental problem facing geothermal power will have been eliminated.

Air Pollution Factors.

Air Pollution. Noxious gases are often a by-product of geothermal wells and hydrogen sulfide (H_2S) is generally the most prevalent. It exists in the steam with other gases, most notably carbon dioxide. The noncondensable gases average 1 percent of the steam flow at the Geysers.(W-30) Of this, 79 percent is CO_2, 5 percent methane, 1 percent hydrogen, 3 percent inerts, 5 percent H_2S, and 7 percent ammonia.

The above figures indicate that H_2S is present in the steam to the amount of 500 parts per million (ppm). If a total of 1,000 MW of power were produced there, this would require 430 million pounds/day of steam. Thus, 215,000 pounds/day of H_2S will be released. Other figures(W-31) suggest that the amount of H_2S released at the Geysers would be less, about 100,000 pounds/day.

Using the data from Cerro Prieto, an estimate can be obtained of the amount of H_2S that might be found in a field yielding hot water. It has been reported(W-32) that H_2S is present in the amount of 0.26 percent by weight in the steam. Other data supplied by the geothermal project at the University of California at Riverside indicate substantially smaller amounts, with wide variations between individual wells. If the higher value is assumed, and a steam rate (20 pounds/kwhr), a 1,000 MW plant would lead to the production of 1,250,000 pounds/day of H_2S. This number exceeds that found in fossil plants burning high sulfur fuel. Thus, it is seen that noxious gas control is apt to be an essential part of geothermal power production. If necessary, technology is available to prevent the release of these gases if extensive fields are developed.

In addition to H_2S, there most certainly could be other chemical species which would adversely affect the environment if discharged into the atmosphere. Some of these might be Radon-222, lead 210, or ammonia. Other emissions associated with drift from the cooling towers, e.g., boron, heavy metals, and fluorides, can degrade the surrounding environment. Rain water and other natural processes may spread this over a larger area. The severity of any of these contaminations will be site dependent and must be weighed separately and carefully. In general, solutions can be found to prevent this contamination; the most drastic would be an enclosed system.

Thermal. The significant environmental effect to be expected in routine operation of a geothermal power plant is heat rejection. All power production cycles using thermal energy reject heat, and the less efficient they are, the greater is the heat rejection. Geothermal steam is available at low pressure and temperature, when compared with that from conventional boiler or nuclear plants. Thus, the heat rejection will be higher. This is clearly indicated by the comparative steam rates (which can be roughly equated to comparative heat rejection) for the Geysers and a modern fossil plant. The rate for Geysers' numbers 3 and 4 plants is given as 18.53 pounds/kwhr, while Moss Landing 6 and 7 is shown as 6.68.(W-31)

For 100 psi inlet conditions, and a water tower-cooled condenser, thermodynamic calculations show that 3,630 MW of heat are rejected by a 1,000 MW geothermal electric plant (a 1,000 MW nuclear power plant rejects approximately 2,000 MW of heat). Water yielding geothermal fields can be expected to have heat rejection rates several times this.

If air-cooled condensers are used, the rejected heat will be larger and will go directly to heating the atmosphere. How this heated air would distribute itself and affect the local climate will require detailed consideration of local conditions. If water cooling towers are used, the temperature would be affected to a lesser extent, but substantial quantities of water would be evaporated, thus influencing the humidity. Considering the heat rejection rate, and for typical cooling tower performance, up to 50,000 acre-ft/yr of water will be evaporated by a 1,000 MW plant.

This amount of reject energy is small when compared to the solar heat input over even 10's of square miles. Thus, no large-scale environmental effects are expected. However, in the immediate vicinity of a concentration of several 1,000 MW plants, considerable environmental effects are possible.

Well Blow Out. In any well drilling operation involving high pressure fluids, the possibility of a well blow out must be considered. Such a blow out affects land, water, and air. For this reason, it is considered separately.

The classic oil well blow out is one type that can occur. Such a blow out can release large quantities of brine if it occurred in a water yielding geothermal field. The release of the brine into waterways and agriculture areas would cause severe local environmental problems.

Listed in Table W-5 are the typical environmental burdens that might be experienced with a 1000 MW geothermal plant.

Energy Systems Development Cost

As indicated, geothermal energy is commercially utilized today on a small scale. However, a program to expand its utilization on a major scale has been described on a preliminary basis in September, 1972, by W. Hickel, et al.(W-23) This program includes the following subject areas:

TABLE W-5. BURDEN OF ENVIRONMENT 1,000 MW GEOTHERMAL PLANT (Subject to very wide variation with source of geothermal heat and recovery system used.)

Effluent or Environmental Effect	Quantity	Anticipated Regulation
Thermal Effects	dry steam 4,000 MW wet steam 10,000 MW	
Air Pollution Contaminants	NO_x - No problem	?
	SO_2 - dry steam Geysers $3(10)^4$ tons/year	?
	wet steam Cerro Prieto $2(10)^5$ tons/year	?
	Solid Particulate - No problem	?
	Trace chemical species - Variable by site, tons/year	0 to minimize
Water Pollution Contaminants	dry steam $3(10^9)$ gal/year	0 release
	containing 10^5 ton/year solids Geysers	
	wet steam $5(10^{10})$ gal/year	
	containing $5(10)^5$ tons/year - Cerro Prieto[a]	
	$5(10)^7$ tons/year - Salton Sea	
Land Despoilment	3,000 - 5,000 acres	
Geological Effects		
Seismic and Subsidence	Possible problem of unknown extent. Cost of monitoring must be considered.	None allowed
Ecological Effects	Minor	Minimize
Social Effects		
Noise	Great	< 100 db
Visual Impact	Great	Minimize

(a) Cerro Prieto will be operating in January 1973. Environmental information available after startup and actual operation will be valuable for future assessments.

Resources Exploration
Resource Assessment
Reservoir Development and Production
Utilization Technology and Economics
Environmental Effects
Institutional and Legal Aspects.

The research needs of each of these subject areas was explored in detail for 2 days by a panel of 8 to 10 recognized experts (total about 60). Thus, the results of these efforts represent the latest opinions of the most knowledgeable people working in the area. Table W-6 tabulates their recommendations for the 1974 to 1983 decade. Other funding recommendations could be made but it is felt that the immediacy of these recommendations, plus the combined knowledge of the assembled experts, is sufficient to justify its use here. However, this particular aspect should be studied in more detail in the future.

Compilations of the estimate of R&D costs are shown below.

Estimated Costs for Geothermal R&D Program

R&D Cost Range - $500 million to
$1 billion

R&D Time Range - 5 to 15 years

Estimated Funding Effort and Requirements
(millions of 1972 dollars)

Expenditure to date	Expenditure Through the Year (for each period)				
1972	1975	1980	1985	1990	Beyond 1990
$10	$110	$420	$270	$250	$300

The estimates of the amount of energy that can be developed vary widely. An estimate number for the United States by the year 2000 is 400,000 megawatts.(W-23, W-33)

Effectiveness and Economic Costs for Pollution Control

A very preliminary estimate of the cost to achieve forecast requirements for pollution control is shown in Table W-7. The primary environmental burden is from waste heat. The low thermal efficiency (∿20 percent) results in rejection of 4,000 MW of heat for 1,000 MW of capacity. If it is assumed that such a plant uses the same types of heat rejection systems as current fission power plants and that the two types of plants have the same MW capacity, the cost for the waste heat dissipation system for the geothermal plant then becomes dependent primarily on the thermal efficiency of the plant. For the most probable range of thermal efficiencies, the relative cost of the waste heat dissipation systems for a 1,000 MW geothermal plant are as follows:

TABLE W-6. PROPOSED GEOTHERMAL RESOURCES RESEARCH PROGRAM (W-23)
(Millions of Dollars)

	Fiscal Year										
	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	Total
Resource Exploration	5.0	8.0	11.0	9.5	6.0	3.5	2.0	1.5	1.5	1.5	49.5
Resource Assessment	15.6	23.4	27.8	29.4	31.2	30.4	30.3	31.3	30.3	24.0	273.7
Reservoir Development and Production	5.0	13.5	27.0	44.0	48.0	21.5	23.0	13.0	10.5	10.0	215.5
Utilization Technology and Economics	9.9	9.9	11.9	11.8	10.5	9.1	9.1	9.1	9.1	9.1	99.5
Environmental Effects	4.2	4.2	3.8	3.6	3.5	3.3	3.3	3.4	3.4	3.3	36.0
Institutional Considerations	2.0	2.0	1.5	1.5	1.0	0.5	0.5	0.5	0.5	0.5	10.5
Totals	41.7	61.0	83.0	99.8	100.2	68.3	68.2	58.8	55.3	48.4	684.7

Thermal Efficiency	Relative Cost for Waste Heat Dissipation System
10	2.47
15	1.87
20	1.52
25	1.28
33.3	1.00

TABLE W-7. EFFECTIVENESS AND ECONOMIC COSTS (1972 Dollars) FOR POLLUTION CONTROL WITH RESPECT TO MEETING EXISTING AND ANTICIPATED REGULATIONS

(Geothermal Power 1,000 MW Plant--Capital Costs Only)

	Effectiveness, percent	Cost, $
Thermal effect	95.0	20,000,000 - 50,000,000
Air pollution	99.5	5,000,000
Water pollution	100.0	5,000,000
Land despoilment	90.0	5,000,000
Geological effects	90.0	2,000,000
Social effects	90.0	2,000,000

Thermonuclear Fusion

Introduction

It is generally recognized by scientists that controlled fusion will play a central role in meeting the energy requirements in the near-term future. This recognition is based on favorable technical factors and on a consideration of alternative fuel reserves. The technical outlook was recently reviewed by the Joint Committee on Atomic Energy(W-34) and progress in theoretical descriptions and confirming experiments have permitted optimistic projections for scientific feasibility demonstration experiments and subsequent controlled thermonuclear reactor (CTR) systems. The impetus for fusion which derives from a consideration of fuel reserves is illustrated in Table W-8. These results clearly show the relative shortage of fossil and rich-ore fissile fuels are the driving force toward CTR.

The basis for fusion power is the energy released in combining light elements with a consequent release of nuclear binding energy. At ordinary temperatures these nuclei are prevented from combining by electrolystatic repulsion but fusion can be achieved if these nuclei must be heated to temperatures near 50,000,000 C to provide sufficient thermal energy for fusion reactions to occur at a useful rate. At these temperatures the nuclei are completely stripped of electrons and the subsequent electron/ion region is referred to as a plasma.

TABLE W-8. WORLD ENERGY RESERVES OF "INFINITE FUELS"(W-35,W-36,W-37)

Energy Source	Years at 2.8×10^{18} Btu Per Annum(a) Known	Years at 2.8×10^{18} Btu Per Annum(a) Possible
Fossil		
Coal	6.8	100
Oil and Natural Gas	1.8	25
Total	8.6	130
Fissile		
Rich-Ore Burners	2.7	7.1
Low-Grade Ore Burners	$1.0(10)^4$	$3(10)^4$
Rich-Ore Breeders	107	340
Low-Grade Ore Breeder	$3.4(10)^5$	$(10)^6$
Total Rich Ore	110	347
Total Low-Grade Ore	$3.5(10)^5$	$(10)^6$
Fusion		
Deuterium	$(10)^9$	$(10)^9$
Lithium	$(10)^6$	$(10)^6$
Solar	$(10)^{10}$	$(10)^{10}$

(a) The value of 2.8×10^{18} Btu is the quantity estimated to meet projected world population needs with per capita consumption rate of United States in 1970.

There are a number of energy cycles which can potentially be used in a CTR. Some of the more prominent cycles are shown in Table W-9. In addition to these cycles, there are other reactions with isotopes of higher Z number which can undergo fusion.(W-38) Their application is not as promising at this time, however, as the reactions displayed in Table W-9. In Table W-9, the initial reaction, the deuterium-tritium (D-T) reaction, is the reaction that probably will receive the bulk of the attention in the early commercial stages of exploitation of the fusion process because the ignition temperature is lowest. Therefore, the rest of this discussion will center around this particular energy cycle. In the D-T reaction the available energy resides in an energetic neutron; in other cycles the energy can largely be found in charged particles. It is worth pointing out that any deuterium fueled fusion plant would have all of the reactions given in Table W-9 taking place to some degree. Therefore, problems identified with the D-T cycle would exist to some degree in other fuel cycles.

TABLE W-9. PROMINENT CTR ENERGY CYCLES

Reaction	Reaction Products	Total Energy (Mev)
${}_1H^2 + {}_1H^3$	${}_2He^4 + {}_0n^1$	17.6
${}_1H^2 + {}_1H^2$	${}_1H^3 + {}_1H^1$	4.03
${}_1H^2 + {}_1H^2$	${}_2He^3 + {}_0n^1$	3.27
${}_1H^2 + {}_2He^4$	${}_1H^1 + {}_2He^4$	18.3

Description of the Energy System

Because significantly high-power levels have yet to be demonstrated in the laboratory, it is premature to discuss the design of a CTR power plant. However, based upon the available experimental data and some informed speculations, one can describe some of the main features of a conceptual power station.

Two distinct methods are being seriously considered for creation of a controlled thermonuclear reaction. They can be grouped according to the scheme proposed for confinement of the ion plasmas. In order to create a controlled thermonuclear reaction, it is necessary that one create a hot gaseous plasma of the desired reacting constituents (i.e., deuterium and tritium) and that this plasma be confined for a time period which is long compared to the fusion reaction time. The two methods which have been proposed for confinement are the electromagnetic confinement method and the inertial confinement method.

The electromagnetic confinement method is based upon the observation that plasma containing energetic ions can, in principle, be shaped by one or more electromagnetic fields. This method of confinement has received the bulk of the research effort to date.(W-39,W-40) Several geometric configurations have been proposed for developing the required magnetic fields. The configurations can be broadly classed as the cylinder or open geometry and the toroidal or closed geometry. In the open geometry a magnetic field confines the plasma in a long cylinder and magnetic "mirrors" are placed at the ends of the cylinder to minimize end losses. In the closed geometry a continuous torus is used as the confining geometry. Both the mirror and torus geometries are distinguished by a number of different concepts which involve varying geometrical conditions, magnetic field configurations, and plasma conditions. At the moment, the most successful approach appears to be the Tokamak variation of the torus group. In the Tokamak system large currents induced in the plasma provide strong resistive heating and supply an important component of the confining magnetic field. Since the field is generated by induced currents instead of external windings, a compact fusion reactor is possible in a toroidal geometry. Successful experiments in the USSR in 1968 have turned worldwide research attention to Tokamak. In most considerations of magnetically confined systems the facility costs force the system toward large generating capacities, typically 10,000 MWt.

Inertial-confinement systems are based on heating the fuel at a rate which is fast compared to the expansion of the resultant plasma. One of the fastest developing inertial-confinement concepts involves laser-induced microdetonations.(W-35, W-41) Major improvements in design have made giant pulsed glass lasers available at an acceptable cost. These are capable of delivering the necessary energy in short bursts (about 10,000 joules in one billionth of a second or less), and are believed to be adequate for demonstrating feasibility. The relatively low efficiencies typical of glass lasers are a disadvantage that can probably be overcome either by further development or, to speculate a little, by devising suitable gas lasers; efficiencies approaching 50 percent have been reported for carbon monoxide lasers. One strong advantage of this concept is that it eliminates the need for large superconducting magnets which are required for the electromagnetic approach. This permits system designs of smaller total generating capacity, perhaps a few-hundred MWt.

Both the magnetically-confined and inertially-confined concepts employing D-T share the need to produce tritium artificially because natural supplies are insufficient to support the need. Figure W-3 illustrates this cycle. Lithium is placed in the blanket to accomplish this goal. Therefore, the D-T energy cycle can be thought of as a deuterium-lithium (D-Li) cycle, and, in fact, the viability of this cycle is limited by the available lithium supply although the known lithium reserves have been estimated to be adequate for tens of thousands to millions of years.(W-35, W-37)

The fuel cycle shown in Figure W-3 would, of course, vary somewhat depending upon the final CTR design. However, the major processes have been identified. Recovery of deuterium (from fresh or seawater) is a complex but well understood technology by itself. Presumably, the mining and refining of lithium metal can be readily defined. The recovery, handling, and injection of tritium bred in the reactor blanket is somewhat less well understood, but it is accepted that these functions are necessary.(W-42)

A number of different energy conversion schemes could be utilized depending upon the specific characteristics of the plasma and design of the

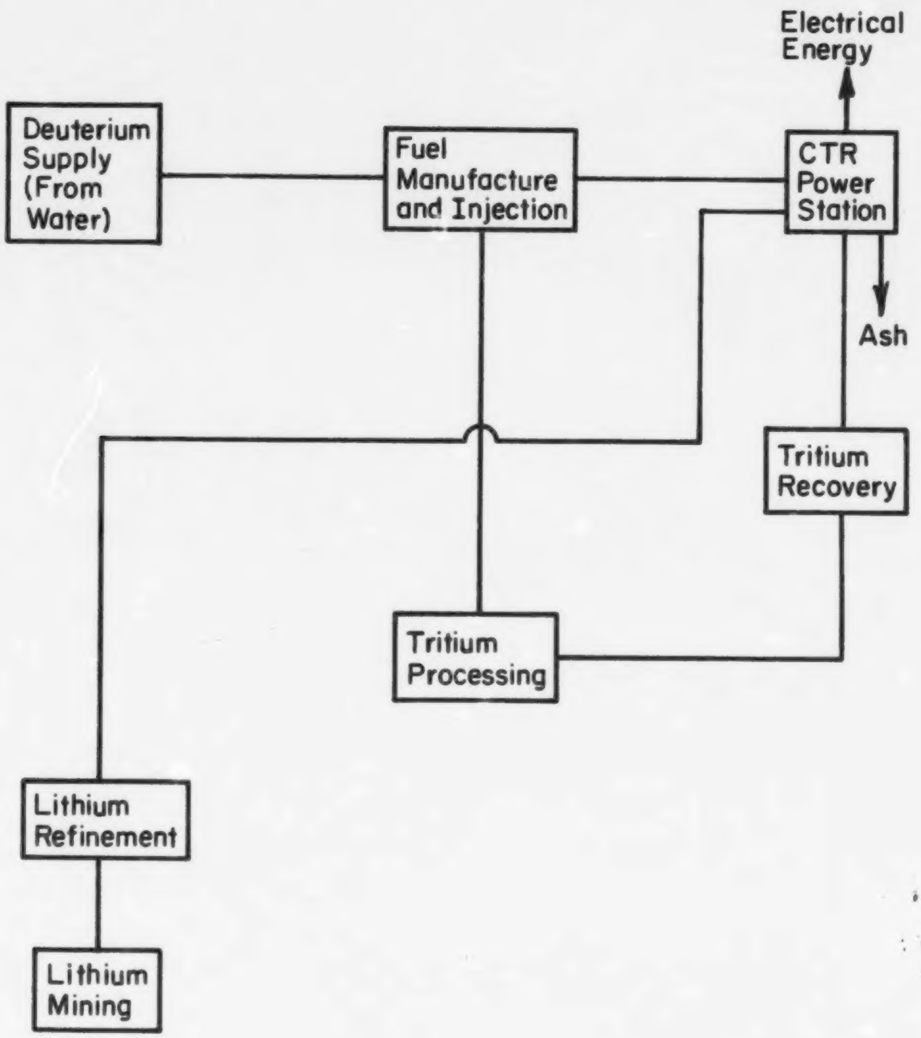

Electrical Energy
Deuterium Supply (From Water)
Fuel Manufacture and Injection
CTR Power Station
Ash
Tritium Recovery
Tritium Processing
Lithium Refinement
Lithium Mining

FIGURE W-3. CONCEPTUAL DEUTERIUM TRITIUM FUEL CYCLE reactor. It would seem likely that the initial power plants would employ conventional steam turbines. A second generation plant could possibly employ a liquid metal topping turbine, as suggested by some investigators,(W-43) to improve plant thermal efficiencies. If developed, large-scale gas turbines would be particularly attractive for application to CTR power plants. Finally, because a significant fraction of the energy of some fusion reactions is given off in the form of charged particles, a direct conversion scheme similar to the operation of a charged particle accelerator in reverse, appears conceptually possible.(W-44) In this case presumably the unit would have both a direct and an indirect conversion system with resultant high net thermal efficiency.

Both the magnetically- and inertially-confined systems would employ some form of a pressure vessel to contain the plasma vacuum. Certain exotic metals capable of high-temperature duty, such as vanadium, molybdenum, and niobium have been suggested for the structural component of this vessel. At the present time, there is not sufficient data to make a clear selection and, in any case, it would appear that the initial plant would employ steel as the vessel structural material. The more exotic metals would probably come into play with the development of a second generation unit.

Based upon the previous discussion, one can develop a rough conceptual design of a power station based upon the two confinement methods. The major elements of such a station are:

- A plasma confinement and heating scheme
- A plasma vacuum vessel
- A moderating and shielding blanket
- A fuel handling and refueling system
- A power conversion unit.

Based upon these elements, Figures W-4 and W-5 display conceptual designs of probable first generation CTR power stations. Figure W-4 shows an electromagnetic confinement station and Figure W-5 shows an inertial confinement station.

Detailed cost estimates for either magnetically-confined or inertially-confined systems cannot be made because plant engineering cannot proceed without basic design information. In general, however, among the crude estimates that have been made, the reactor plant equipment and nuclear engineering costs for the magnetically-confined systems are slightly higher than those for breeder reactor systems and these costs for the inertially-confined systems are competitive with these systems.(W-35) An example of projected costs for a magnetically-confined system are:(W-45)

Nuclear Boiler	\$60-70/kw(e)
Magnets	\$30-60/kw(e)
Fuel	0.00035c/kwhr
Other	\$70-100/kw(e)
	~\$200/kw(e)

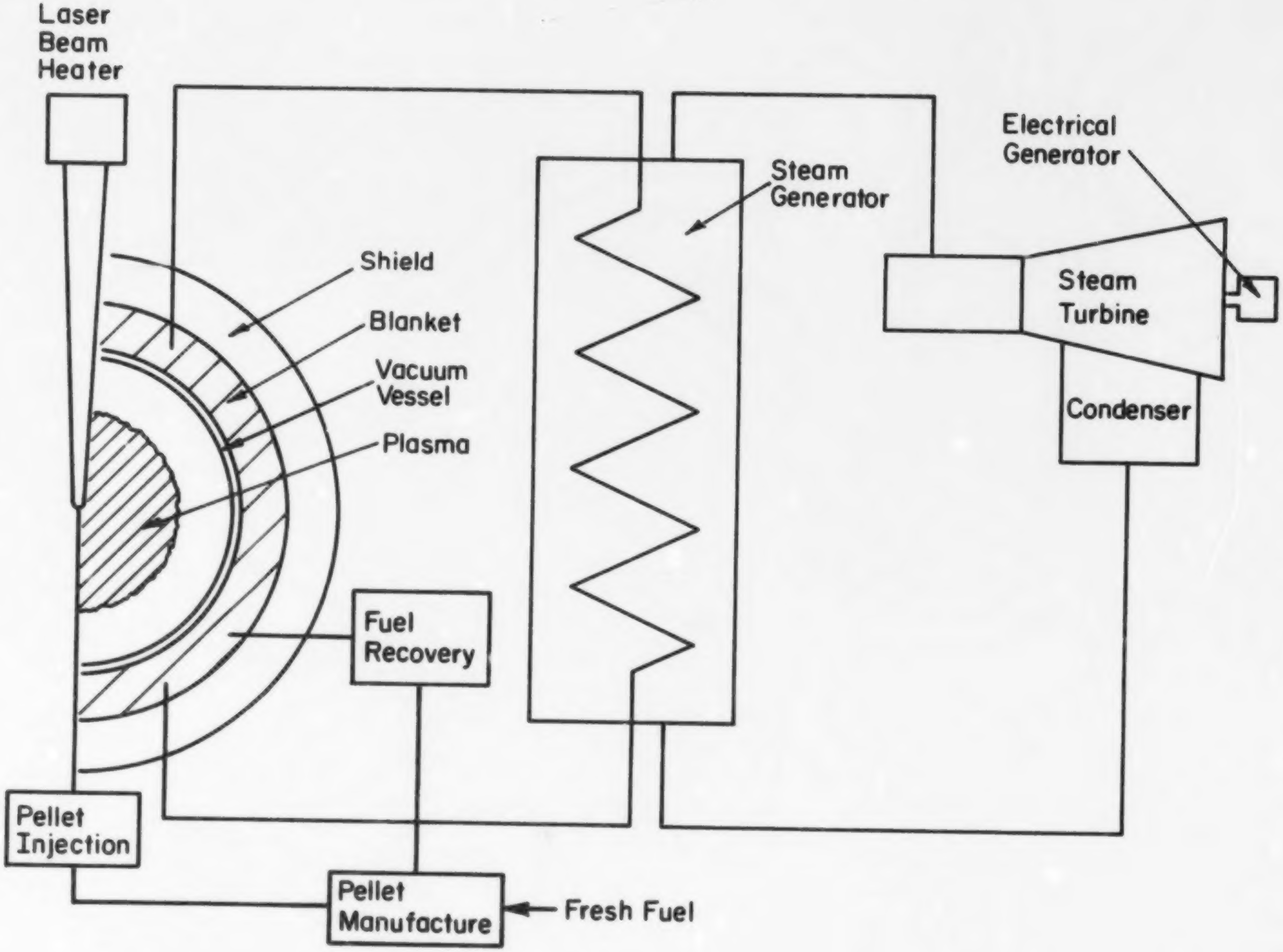

Laser
Beam
Heater
Shield
Blanket
Vacuum
Vessel
Plasma
Fuel
Recovery
Pellet
Injection
Pellet
Manufacture
Fresh Fuel
Steam
Generator
Electrical
Generator
Steam
Turbine
Condenser

FIGURE W-4. CONCEPTUAL DESIGN OF AN INERTIAL CONFINEMENT CTR POWER PLANT

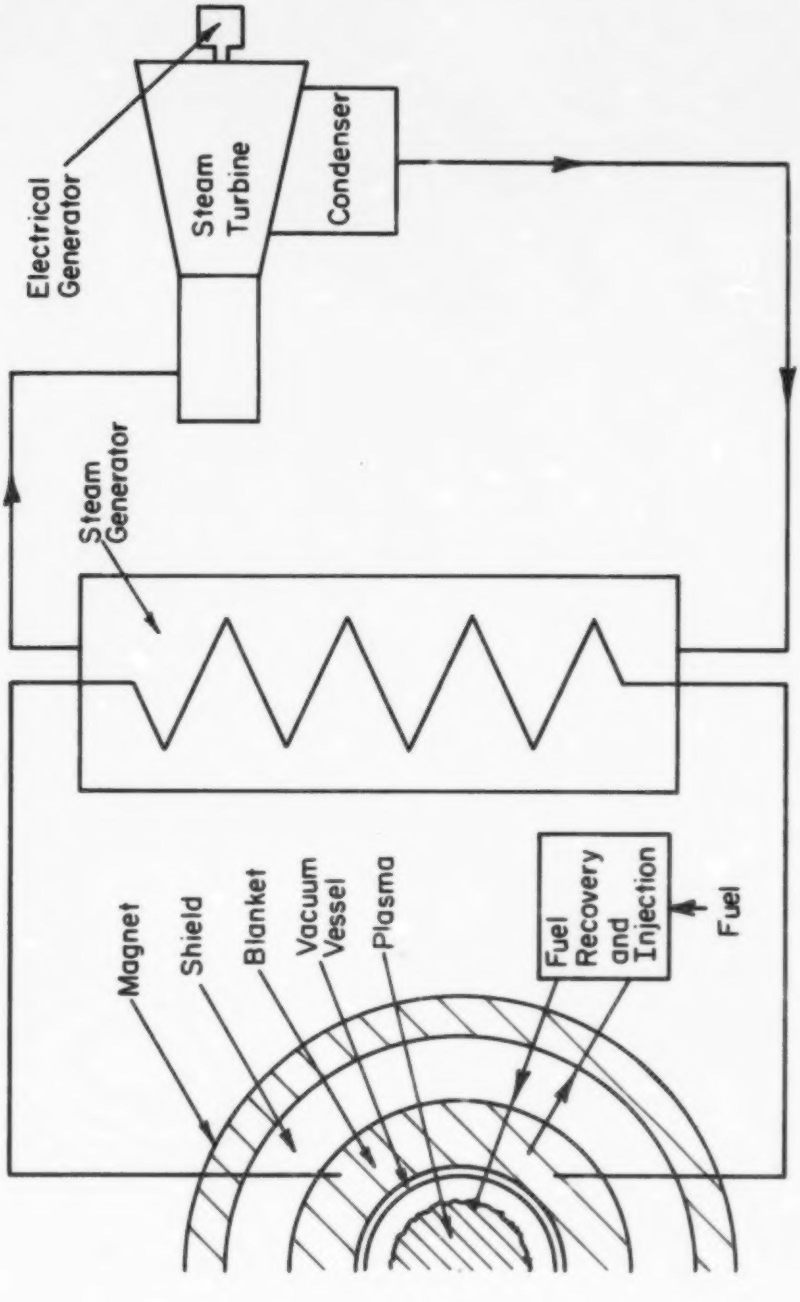

Electrical Generator
Steam Turbine
Condenser
Steam Generator
Magnet
Shield
Blanket
Vacuum Vessel
Plasma
Fuel Recovery and Injection
Fuel

FIGURE W-5. CONCEPTUAL DESIGN OF AN ELECTRO-MAGNETIC CTR POWER PLANT

Environmental Burden

One principle advantage of a fusion power system over a fossil system is the total absence of combustion products; this advantage is shared with fission plants. Another advantage of fusion power is that radioactive waste is localized relative to fission plants because no fission product inventory, or radioactive material reprocessing, is associated with the operation. The possibility of direct conversion of the highly charged fusion products into electricity with the attendant advantage of thermal efficiency has been cited.(W-46) Another noteworthy advantage of fusion power is the freedom from a nuclear excursion or criticality accident which is a concern of all fission power systems. This is a consequence of the physics of operation; fusion entails no "critical" quantity of fuel and the associated possibility of an "over criticality" condition.

Although these relative advantages exist, fusion power will have an environmental impact. Except for the direct conversion concepts, a conventional thermodynamic cycle is contemplated with the accompanying problems of thermal effluents. Probably higher temperatures will be employed with the attendant reduction in waste heat per unit electrical power, but this is usually a modest savings (perhaps 15 to 20 percent at best). The fusion plant will likewise have a chemical discharge from coolant treatment and other metal/chemical discharges. These are not unique to the system and, therefore, are not discussed further here.

The effluents which are peculiar to a fusion reactor power plant are summarized in Table W-10.

TABLE W-10. SUMMARY OF EFFLUENTS FROM D-Li ENERGY CYCLE

Effluent	Source	Release Point
Tritium	Bred in Reactor from Lithium	Leakage Through Reactor Wall
Fusion Ash ($_2He^4$, etc.)	Created in Reactor	Release from Plant
Waste H_2O	Deuterium Collection	Isotope Separations Plant (Back to Source)
Lithium Tailing	Mining Process	Refining Process
Radioactive Waste	Neutron Reactions with Structural Components or Reactor	At Plant Disassembly or

Of the effluents created by the D-Li energy cycle, tritium has probably the largest potential environmental impact. The D-Li energy cycle would consume .2 kg of tritium per day per 1000 MWt. The station inventory has been estimated to be between 1 to 15 kg per day per 1000 MWt;(W-47) this is about 1,000 to 100,000 times the lithium inventory in a fusion plant. If the inventory per 1000 MWt is 1 kg, the plant leak rate must be .0012 percent per day in order to meet existing regulatory standards. The current technology for leak rates on large systems such as nuclear power stations is higher by one to two orders of magnitude.(W-39)

As currently envisioned the radioactive waste associated with the D-Li energy cycle comes primarily from neutron-induced structural activation. If stainless steel is used the activation rate is expected to be comparable to vanadium or molybdenum whose long-term activity has been estimated to be one-thousandth that of a comparable fission power plant.(W-47) If niobium is selected as the base structural material, radioisotopes of Nb, Y, and Zr will be formed and activity comparable to a LMFBR can be anticipated. While the opportunities for dispersion of this material do not exist in a manner comparable to an LMFBR, it does represent an ultimate burden on the environment. A more detailed evaluation of this is needed.

Small quantities of the ash from the fusion process would be released from the D-Li fusion cycle. The D-Li cycle will produce and presumably release about 250 grams of $_2\text{He}^4$ per day per 1000 MWt.

In order to separate the deuterium required for the D-Li cycle, it will be necessary to use, in a nonconsumptive manner, some 16,000 gpm of seawater per 1000 MWt of installed capacity to meet the makeup fuel requirements of the plant.(W-48) By comparison, about 240,000 gpm of cooling water would be required to disperse this amount of heat.

The lithium mining cycle would produce measurable quantities of effluents. Perhaps the best way to characterize the mining problem is by way of comparison to the uranium fuel cycle. Assuming a strategy based upon total use of both fuels, about one-third as much lithium needs to be mined as compared to uranium (by weight) provide the same power level. In terms of inventory, however, the lithium requirement would be several times that of the uranium. Thus, the lithium mining impact can be expected to compare to the uranium mining impact.

The potential impact of effluents is summarized in Table W-11 for a 1000 MWe power station employing an operating efficiency of 40 percent. Many of the results in Table W-11 are speculative and must remain so in the absence of a designed and operating station.

Development Schedule and Costs for Fusion Power

An estimate of 4.24 billion dollars to bring fusion power to the point of commercial viability has been made by the R&D Goals Task Force of the Electric Research Council.(W-49) This figure is broken down by milestone (or function) in Table W-12 and by year in Table W-13. Also included in Table W-13 are the Atomic Energy Commission estimates for an expanded program and an all-out program are compared with the Electric Research Council figures through the year 1980.

TABLE W-11. D-Li ENERGY CYCLE EFFLUENTS 1000 MWe, 40 PERCENT EFFICIENCY

Effluent	Amount Released	Assumptions	Relative Impact Compared to LWR
Tritium	.41 Rem/day	.0005% leak rate; 5 kg inventory	Comparable
Heated Effluent	5.9×10^9 Btu/hr	40% thermal efficiency	Comparable
Fusion Ash	.63 kg/day	Total release	Trivial
Waste Water	40,000 gpm	Makeup only	Trivial
Lithium Tailings	35% of uranium	Ultimate use	Comparable
Radioactive Waste	1-5% of LWR	Stainless structure	Small

TABLE W-12. NUCLEAR FUSION COSTS (BY MILESTONE)

	Millions of 1971 Dollars
Expended Through FY 1971	400
Proposed	
Demonstration of Feasibility	450
Physics, Engineering, and Materials	2,090
Direct Conversion Prototype	300
Thermal Prototypes (2)	400
Demonstration Plants[(a)]	1,000
Total, future	4,240

(a) Incremental cost for small plants above equivalent fission capacity in large plants. If very large (2,000 to 5,000 MW) demonstration plants are necessary, this figure is too low.

Effectiveness and Economics of Pollution Control

At present there are no low cost systems for isolating and storing tritium leaking from a reactor system. The tritium usually appears at a very low concentration in air or water streams such that concentration by known methods would be very costly. It is assumed herein that no attempt is made to isolate tritium escaping from the system.

TABLE W-13. NUCLEAR FUSION COSTS BY YEAR IN MILLIONS OF 1971 DOLLARS

Year	Utility Estimates	AEC Estimates	
		Expanded Program	All-Out Program
1973	60	45	74
1974	95	58	143
1975	110	65	190
1976	135	76	215
1977	160	81	237
1978	170	83	--
1979	215	86	--
1980	245	89	--
1981-1985	1000	--	--
1986-1990	1000	--	--
1991-1995	500	--	--
1996-2000	500	--	--

Escape of ${}_2He^4$ creates no environmental problems. It is assumed that no waste treatment systems are necessary.

No treatment processes are assumed necessary for the wastewater from deuterium production processes. Normally that water is of equal or better purity than when it was obtained from its source. In some cases, though, treatment may be necessary for removal of residual corrosion inhibitors or process chemicals.

The waste heat from a fusion device must be dissipated either in a water or air sink in the same manner as for current power plants. The costs for constructing and operating the waste heat system may be lower per MWe of capacity than for LWR because the fusion reactor could possibly have a higher thermal efficiency and a higher power level.

There have been no attempts to extract in detail from the overall R&D costs those associated with environmental quality control. Some parallels might be drawn with fission power sources. In that area it is recommended that ~15 million per year be spent on environmental control research. This is a few percent of the total budget for research. There is much in common between fusion and fission so it might be expected that the additional needs would be lower--say 1 percent of the total R&D costs. This would mean that an additional 40 million dollars would be required to meet environmental research needs over the next 20 to 30 years if the total estimated cost of Table W-12 is accepted. Apart from these estimated research costs a continuing radioactive materials management cost has been estimated to be 0.03 to 0.05 mill/kwhr.(W-50)

Breeder Reactors

Fission Gas-Cooled Fast Breeder Reactor

The gas-cooled fast breeder reactor,(W-54, W-55, W-56, W-57) as presently visualized, will utilize metal-clad refractory fuel in a core that is cooled by the forced circulation of pressurized gas. The concept involves a wedding of LMFBR fuels technology and gas-cooled thermal-reactor (AGF and HTGR) component technology. The development of the GCFBR lags behind that of the LMFBR by five to ten years with only a relatively low level of current effort. It is doubtful that it will be a commercially significant source of power until the end of this century. The development of large, high-temperature gas turbines would increase the attractiveness of gas-cooled reactors generally and speed the development of the GCFBR.

Description of Energy System. Figure W-6 shows a suggested power cycle for the early 1000 MWe GCFBR's. A conventional steam cycle is projected in line with current gas-cooled power plant technology. Core-coolant exit temperatures are limited by fuel-pin performance limitations which are in turn directly influenced by the use of stainless steel cladding on the fuel. The helium is pumped through the core at high flow rates by means of helium circulators. The heated helium is used to produce steam in a steam generator and is then recycled to the core. The steam side of the system contains a conventional turbine for the generation of electricity.

Potential Environmental Factors. The GCFBR can and will be designed such that the reactor effluent is well within permissible release limits to the atmosphere. Because of its relatively high efficiency (~38 percent), thermal effluent will be significantly reduced as compared with water reactors whose efficiency is only about 30 percent.

The use of helium coolant will result in production of tritium as a result of neutron reaction with ^{3}He. However, this can be readily removed by continuous scrubbing of the coolant gas to remove both tritium and fission-product gases. Disposition of the tritium can be readily accomplished because of the small volumes involved. This is not true in LWR's where the tritium is chemically indistinguishable from hydrogen and one is confronted with the processing and storage of relatively large amounts of tritium-contaminated water.

Fission-product contamination of the reactor system will be minimized in the GCFBR by venting of the fuel to a collection system. Thus, only minimal release to the coolant will occur in the event of a fuel failure. Since helium is inert, leaching of fission products from the fuel by the coolant will not occur as in water and liquid-metal systems. Release in any event will be restricted to volatiles. Since only a gas phase will appear in the complete primary circuit, only a single recovery system will be required.

Tidal Power

Because of the 24-hour, 50-minute tidal cycle, the availability of energy from tidal flow in large estuaries gradually shifts throughout the day. Thus, when large slugs of energy become available from tidal movement at times of low demand on the system, pumped storage is required to utilize the tidal output effectively. Hence, recent consideration of tidal power has included pumping plants as well.(W-51) A pumped-storage facility involves additional capital investment, already a serious limitation of proposed tidal power plants.

Only one major tidal power plant is in operation today--at the Rance River estuary on the coast of France near St. Malo. Rated at 240 MW, with a 3,000-foot dam impounding 6.4×10^9 cubic feet of water using two-way bulb turbines, the plant generates 6.24×10^8 kwhr annually for an availability of about 30 percent. Power generation costs are high compared with modern steam plants, amounting to 2 to 3 times the bus-bar costs of fuel-fired systems because of the high capital charges involved in building a large dam, providing pumped-storage basins to supply power between tides, and in constructing the turbine pumps.

Environmental Burden

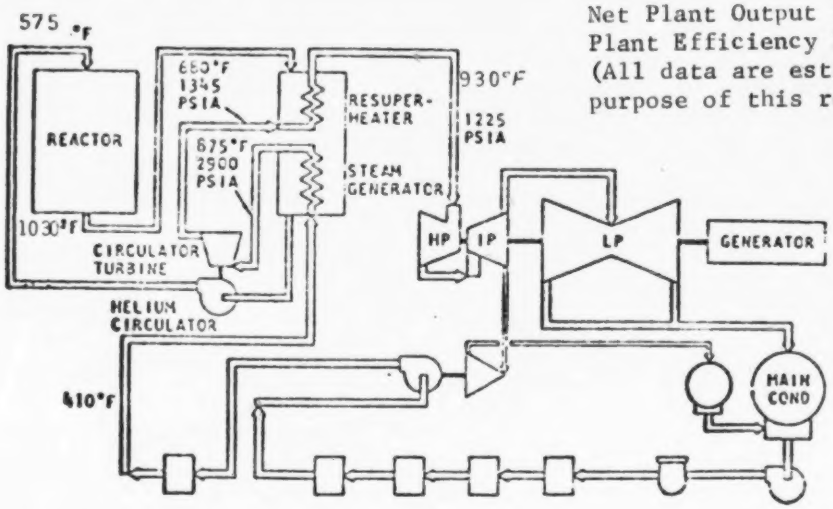
Tidal power has little impact on the environment, mostly involving local actions resulting from disturbing normal tidal flow patterns. Changes in salinity, oxygen content, and water level may affect local fisheries, but no major effect is foreseen on climate or on atmospheric conditions in general.

R&D Requirements

Little R&D is required, the operation at Rance River having provided a "pilot plant" demonstrating both the cost and the feasibility of tidal power plants. The Passamaquoddy situation has been reviewed many times, the conclusions being that the cost of the required dam and the penetrating facilities cannot be justified. Dam-construction techniques are not likely to change unless, some day, nuclear explosives might be utilized in some predictable manner. Likewise, bulb turbines as used at Rance River and in pumped-storage installations perform satisfactorily. Because of the inherent low hydrostatic heads, some turbine development may be desirable,(W-52) but no appreciable power generating gains can be expected through further research.

All of North America is estimated to have some 300,000 MW of tidal energy.(W-53) The potential for power generation is therefore weak, and coupled with the high capital cost, tidal power is not considered a viable source.

For the above reasons, no funding effort appears to be needed.



Net Plant Output 1000 MWe
Plant Efficiency 38%
(All data are estimated for
purpose of this report only)

FIGURE W-6. SIMPLIFIED POWER-CYCLE DIAGRAM, 1000 MWe GCFBR

Because of the higher pressure on the helium side of the steam generator, there is a potential for leakage to and contamination of the steam system. While this can be minimized by appropriate maintenance of the steam generator and cleanup of the helium gas, waste treatment systems will be required to clean up the steam circuit also in order to prevent the possibility of leakage to the atmosphere. However, the potential would appear to be less than from any LWR.

Fission products not recovered on site will eventually be recovered during reprocessing. Most fission products and tritium will require long-term storage to avoid radioactive contamination of the atmosphere. Fast reactors are fueled with plutonium which is highly toxic if inhaled or ingested. Shipment of the virgin fuel will require precautions similar to that required for its shipment after irradiation.

The great advantage of fast breeder reactors, of course, is in their negative fuel usage. The GCFBR is anticipated to exhibit a breeding ratio of at least 1.5, meaning that for each unit of fuel consumed, 1.5 times as much is generated for a 50-percent gain. The fuel is ^{239}Pu and smaller amounts of ^{241}Pu and the fertile material from which additional fuel is bred is ^{238}U. The goal in fuel performance is to achieve an electrical power output of at least 10^6 kwhr/kg of fuel and fertile material before it must be reprocessed.

Energy Systems Development Costs. A wide range of development efforts are required to bring the GCFBR to the stage of commercial feasibility. However, the most critical involve (1) core-cooling requirements in the event of less of helium pumping power; (2) improved fuel-pin design, including consideration of cladding material, fuel venting, and surface heat transfer; and (3) design of the necessary pressure vessel.

An estimate of required R&D costs and time prior to construction of a commercial size GCFBR 1000 MWe power plant and including construction of a smaller (300 MWe) demonstration plant is given below.

R&D Cost Range	$750,000,000
R&D Time Range	20 years.

Fission-Molten Salt Breeder Reactor

The Molten-Salt Breeder Reactor(W-58, W-59) (MSBR) is a thermal reactor concept operating on the ^{232}Th-^{233}U fuel cycle which is capable of breeding by continuous removal of fission product wastes and ^{233}Pa from the fuel-containing salt. The Pa decays to ^{233}U which is then returned as fuel to the reactor. Research and development already accomplished on MSBR materials and processes indicate that after the technology has been extended in a few specific areas, a prototype MSBR could be successfully constructed and operated.

Molten salts have been under study and development as reactor fuels and as coolants for over 20 years. Their chemical, physics, and irradiation properties are excellent. The Molten-Salt Reactor Experiment (MSRE) contributed significantly to MSR technology during its 5 years of operation. Research in the processing of molten salt fuels showed that ^{233}Pa and fission products could be separated from salts containing both uranium and thorium by reductive extraction into liquid bismuth. Oak Ridge National Laboratory (ORNL) has prepared a conceptual design for a 1000 MWe single-fluid molten-salt reactor power plant that indicates such a plant is technically feasible and economically attractive.

The major remaining areas for development in the MSBR concept are:

1. The chemistry of noble metal fission product behavior

2. Alternate rare earth removal processes

3. Physical and chemical properties of the secondary coolant salt

4. Continuous methods for analytical process control

5. Engineering development of fuel processing equipment for contactor, fluorinator, electrolyzer, and vacuum distillation

6. Improvement in materials such as radiation-damage resistant graphite, container materials (Hastelloy N), and container material for simultaneous contact of molten Bi and salt at 500 to 700 C

7. Reactor system components such as pumps, heat exchangers, steam generator, rods and drives, and maintenance procedures.

Description of the Energy System. The reference MSBR operates on the Th^{233}-U cycle, with both fissile and fertile materials incorporated in a single molten-salt mixture of the fluorides of lithium, beryllium, thorium, and uranium. This salt, with the composition $LiF-BeP_2-ThF_4-UF_4$ (71.7-16.0-12.0-0.3 mole percent), has a liquidus temperature of 930 F (772 K), has good flow and heat transfer properties, and has a very low vapor pressure in the operating temperature range. It is also nonwetting and virtually noncorrosive to graphite and the Hastelloy N container material.

The 22-foot diameter by 20-foot high reactor vessel contains graphite for neutron moderation and reflection, with the moderating region divided into zones of different fuel-to-graphite ratios. As the salt flows upward through the passages in and between the bare graphite bars, fission energy heats it from about 1050 F (839 K) to 1300 F (978 K). Graphite control rods at the center of the core are moved to displace salt and thus regulate the nuclear power and average temperature, but these rods do not need to be fast scramming for safety purposes. Long-term reactivity control is by adjustment of the fuel concentration.

The core neutron power density was chosen to give a moderator life of about four years, based on the irradiation tolerance of currently available grades of graphite. The specific inventory of the plant, including the processing system, is 1.47 kg of fissile material per MWe, the breeding ratio is 1.06 and the annual fissile yield is 3.3 percent. The heat-power system has a net thermal efficiency of over 44 percent which makes a reactor plant of about 2250 MWt ample for a gross electrical output of 1000 MWe.

A simplified flow diagram of the MSBR system is shown in Figure W-7. The primary salt is circulated outside the reactor vessel through four loops. (For simplicity, only one loop is shown in the figure.) Each circuit contains a 16,000 gpm single-stage centrifugal pump and a shell-and-tube heat exchanger. Tritium, xenon, and krypton are sparged from the circulating primary salt by helium introduced in a side stream by a bubble generator and subsequently removed by a gas separator. A 1 gpm (0.06 liter/second) side stream of the primary salt is continuously processed to remove fission products and ^{233}Pa and to adjust the fissile content. A drain tank provides safe storage of the salt during maintenance operations.

Heat is transferred from the primary salt to a secondary fluid, sodium fluoroborate, having a composition of $NaBF_4-NaF$ (92-8 mole percent) and a liquidus temperature of 725 F (658 K). Each of the four secondary circuits has a 20,000 gpm centrifugal pump with variable-speed drive. The secondary salt streams are divided between the steam generators and the reheaters to obtain 1000 F steam temperatures from each. Steam is supplied to a single 3500 psia, 1000 F/1000 F, 1035 MWe turbine generator unit exhausting at 1-1/2 inch Hg absolute. Regenerative heating and live steam mixing are used to heat the feedwater entering the steam generator to 700 F (644 K) to provide assurance that the coolant salt remains liquid.

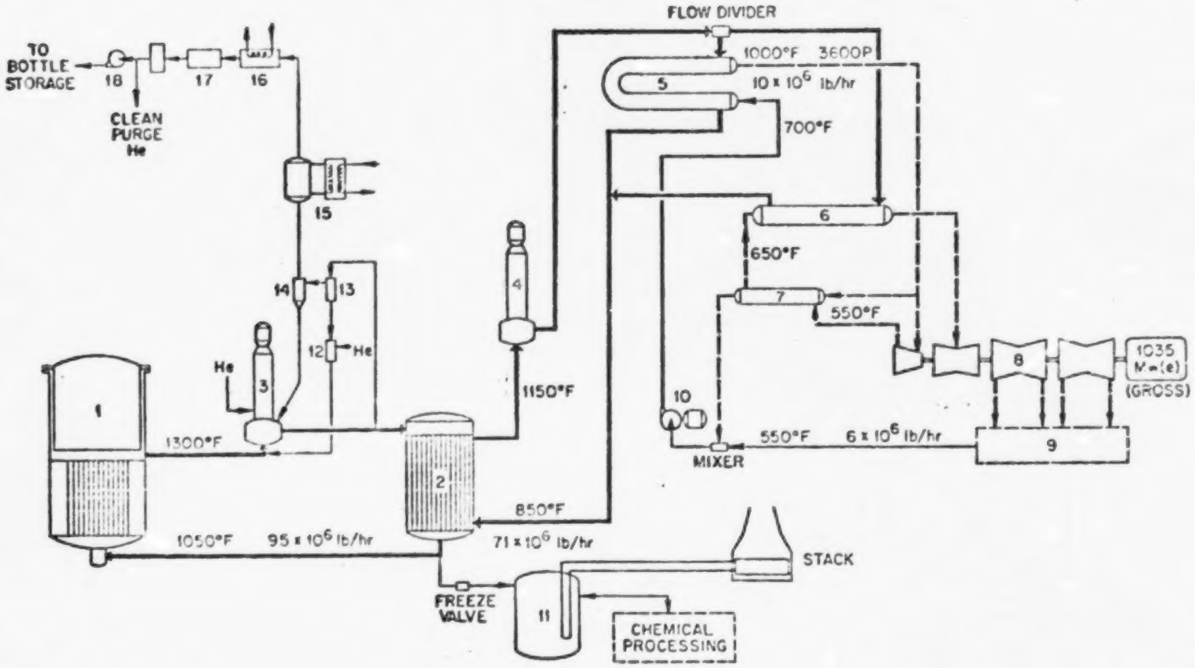

TO BOTTLE STORAGE
18
17
16
CLEAN PURGE He
15
14
13
12
He
He
3
1
1300°F
2
4
1150°F
FLOW DIVIDER
1000°F 3600P
5
10 x 10^6 lb/hr
700°F
6
650°F
7
550°F
8
1035 Mw(e) (GROSS)
10
MIXER
550°F 6 x 10^6 lb/hr
9
850°F
71 x 10^6 lb/hr
1050°F 95 x 10^6 lb/hr
STACK
FREEZE VALVE
11
CHEMICAL PROCESSING

FIGURE W-7. SIMPLIFIED FLOW DIAGRAM OF MSBR SYSTEM. (1) Reactor, (2) Primary heat exchanger, (3) Fuel-salt pump, (4) Coolant-salt pump, (5) Steam generator, (6) Steam reheater, (7) Reheat steam preheater (8) Steam turbine-generator, (9) Steam condenser, (10) Feedwater booster pump, (11) Fuel-salt drain tank, (12) Bubble generator, (13) Gas separator (14) Entrainment separator, (15) Holdup tank, (16) 47-hr Xe holdup charcoal bed, (17) Long-delay charcoal bed, (18) Gas cleanup and compressor system

The estimated plant capital costs for a fully developed MSBR, although differing in breakdown, are about the same as those for a light water nuclear power station. Fuel-cycle costs are expected to be quite low and relatively insensitive to the prices of fissile and fertile materials.

Potential Environmental Factors. The nature of the MSBR system lends itself to the minimizing of the environmental impact of a nuclear power system. Its high efficiency, for instance, reduces the waste heat that needs to be dissipated to about 75 percent of the waste heat for a light water reactor.

In normal operation, the fission gases and tritium are continuously removed from the primary circuit in a form that lends itself readily to collection and packaging. Thus, even though there may be 20 to 50 times as much tritium produced as in an equivalent LWR, it is less likely to be released as water or water vapor to the environment. The nonvolatile fission products are also continuously separated in a relatively small volume and form that is readily packaged and stored. Should salts leak from the system, the tendency will be for them to solidify retaining the fission products, rather than to evaporate and disperse the fission products into the air as an LWR. Because of the continuous processing, the buildup of long-lived fission products is maintained at a minimum. Thus, a major source of heat in event of an accident is considerably reduced. By the same token, the fuel inventory is maintained at the minimum necessary to attain criticality, reducing the potential for an uncontrolled criticality accident. The primary system operates at low pressure, and the salt content is quite inert chemically. Thus, the primary system contains only sensible heat, as contrasted with the latent heat of the pressurized water system, and there is no potential for the metal-water reaction which one finds in the LWR.

All the above factors make the MSBR system one whose environmental impact is likely to be considerably less than that of the LWR.

Development Schedule and Cost. An estimate of the required cost and time for the MSBR system development to be carried through the building and operation of a demonstration plant (300 MWe) is given below:

R&D Cost Range	∿ $1,000,000,000
R&D Time Range - years from 1972	20 years

Estimated funding effort and requirements to produce a demonstration plant are:

	(Millions of Dollars) Expenditure Through the Year (for each period)				
Expenditure to Date, 1972	1975	1980	1985	1990	Beyond 1990
∿$50	$50	$150	$200	$100	?

The magnitude of energy that can be developed by the year 1990 is estimated at approximately 5 GWe.

Liquid-Metal Fast Breeder Reactor

The Liquid-Metal Fast Breeder Reactor (LMFBR)(W-60, W-61, W-62) will use liquid sodium as the coolant and plutonium (^{239}Pu and ^{241}Pu) as the fuel. The fuel will be either dissolved in or mixed with uranium and be contained in metal tubes in the form of ceramic pellets. Breeding of additional plutonium fuel from ^{238}U will occur from the uranium that is contained both within the fuel and in the blanket rods that surround the fueled core. The LMFBR concept has been under study since the early days of the U.S. power reactor development program, but is only now the subject of a concentrated effort aimed at commercial power utilization. Commercial commitments are unlikely until after about 1985 but the LMFBR is expected to become a major power source in subsequent years.

Description of Energy System. The power system of an LMFBR is illustrated in Figure W-8. The system includes an intermediate heat transfer loop between the reactor coolant system and the steam supply system. Sodium serves as both the primary coolant and the heat transfer medium in the intermediate loop. Sodium is attractive for both purposes because of its excellent heat transfer characteristics. An additional attractive feature of sodium is its high boiling point (892 C at 1 atm), so that pressurization of the primary coolant system to suppress boiling is not required.

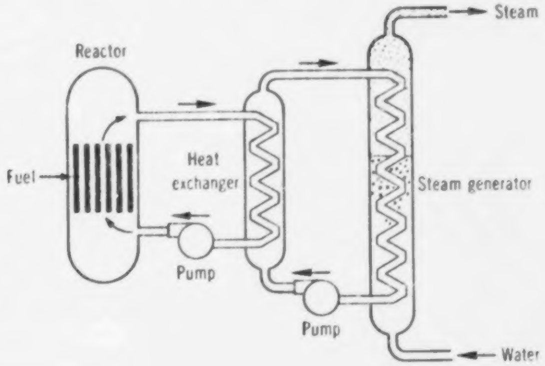


FIGURE W-8. NUCLEAR STEAM-SUPPLY COMPONENTS IN A LIQUID-METAL-COOLED BREEDER REACTOR

Potential Environmental Factors. The LMFBR is anticipated to be operable with a 40-percent efficiency. The increased efficiency relative to a LWR means a decrease by one-third in thermal effluent for an LMFBR plant of equivalent power.

Tritium production in an LMFBR is negligible being restricted to production in the fuel by ternary fission and from possible contaminant ^{6}Li in the sodium coolant by reaction with neutrons. There is no reaction with sodium to produce tritium.

The LMFBR is potentially capable of zero radioactive effluent release at the reactor plant site. The primary system will operate at a pressure close to atmospheric with the secondary sodium system at a slightly higher pressure, both sodium circuits being at a very much lower pressure than the steam-water system. Thus, the possibility of contamination of the latter system as a result of leakage from the primary circuit will be minimal. Consideration is being given to the use of vented fuel pins that would release fission gases directly to the coolant and thence to the cover gas system. The recovery for disposition of the fission products from the cover gas and sodium coolant will be required and this capability is available.

Fission products retained within the fuel will be recovered during reprocessing of the fuel. The fission product volume will be relatively small but will require long-term storage in a controlled area to permit radioactive decay. The storage area will be determined by the exclusion area required rather than the volume of the waste itself.

Because the plutonium fuel is highly toxic, the shipment of fuel to the reactor plant will require the same safety precautions as are needed for shipment of the irradiated fuel. Escape of fuel to the atmosphere during shipment must be avoided.

The breeder, since it creates fuel, has a favorable impact on energy resources. The LMFBR, depending upon the specific fuel type and breeder design, will exhibit a breeding ratio of between 1.2 and 1.5, the lower value probably being typical of early breeders. The ratio means that for each unit of fuel consumed, 20 to 50 percent more fuel is generated than is burned. The use of breeder reactors increases the energy supply from natural uranium by two orders of magnitude.

The electrical energy production in breeder reactors will amount to 10^6 kwhr/kg of combined fuel and fertile material before the fuel is reprocessed. The gross electrical potential per kg of fuel and fertile material is about 9×10^6 kwhr.

The breeder also has a favorable effect on energy use. Because plutonium serves as the fuel and can be chemically recovered, the use of gaseous diffusion plants which consume large amounts of energy is not required, as in the case of uranium as fuel, which requires isotope separation.

Development Schedule and Cost. The LMFBR has been the subject of development since the mid-1940's, although the level of effort has fluctuated considerably. Several experimental reactors, the EBR-I and EBR-II, and a prototype power plant, the Enrico Fermi plant (220 MWt) have been constructed and operated. Nevertheless, the LMFBR is still unproven commercially and the next step will be construction of a 300 MWe commercial power plant with development of the large size components required for a commercial plant involving a major effort.

The demonstration plant is projected for operation by 1982. The 1000 MWe plant will probably not be operational much before 1990. Thus, the LMFBR will not be commercially significant in the United States until the end of this century.

An estimate of the required cost and time for the LMFBR to reach the point of commercial utilization, which covers principally the period up to operation of a demonstration plant, is given as:

R&D Cost Range	$1,000,000,000
R&D Time Range	15 years.

Magnetohydrodynamics

Magnetohydrodynamics (MHD) is an energy conversion process using the advanced technology of plasma flow that has potential application to conventional systems for generating power. When an electrically conducting gas (plasma) is forced through a duct at high velocity in the presence of a transverse magnetic field, the electromotive forces decelerating the gas flow induce an electrical current flow that can be delivered to external load through electrodes appropriately placed along the duct.

Adequate electrical conductivity in the plasma for practical power generation requires both high gas temperature (around 4000 F or 2500 K) and gas flow seeding with readily ionizable materials such as potassium or cesium. In a combustion gas system, an advanced combustion process is required to deliver the hot compressed gas with the added seed to the MHD nozzle where it is expanded into the MHD duct past the magnetic field and the electrodes. The work extraction lowers the plasma temperature to the regime of inadequate electrical conductivity at about 3100 F (2000 K) so either a very large regenerative heat exchange with the combustion air or delivery of thermal energy to another power extraction cycle, or both, is indicated. Some regenerative heating is necessary to achieve the ultrahigh combustion temperature without oxygen enrichment but practical base load systems would feed the MHD exhaust into a conventional steam plant which generates the majority of the electrical power.

Thermodynamically, this high-temperature extraction of work from the combustion products improves efficiency, reducing both the fuel requirements for each kwhr of electrical energy (stretching our natural resources) and the heat rejection for each kwhr of electrical energy (reducing the thermal pollution loading). The cost of seed material is such that the stack gases must be treated to recover it, inherently imposing sophisticated gas cleaning elements in the system so that the pollution demands are more readily accepted. The high flame temperature, however, imposes a uniquely severe NO_x control burden.

Closed cycle MHD systems using either noble gases or two-phase fluids also have been investigated. The Rankine cycle fluid systems have shown themselves to be limited to specialized aerospace application. Brayton cycle MHD systems have been proposed, in particular for gas-cooled reactor systems, but basic incompatibilities seem to virtually eliminate such systems from any current application.

Open Cycle MHD Reserve Power Generators

The reserve power use of open channel MHD is uniquely important for two reasons:

1. Its economic and technical operation is radically different from

base load MHD systems.

2. It will probably be the first commercial application of MHD, presenting an economically convincing case against a backdrop of disappointment with the technological progress in base load MHD.

Because the MHD process is inherently a low inertia process standby, generation for short term power reserves can be shown to be economically very attractive,(W-63) particularly for individual running times less than 5 minutes and yearly total running times on the order of 50 hours (200 days with 4 runs of 4 minutes each). The capital costs control the economics of this system use so the exhaust would be rejected hot and untreated and represents an anomally in emission consideration and procedures. The fuel is clean and uses oxygen rather than air so the major pollution concerns would be the seed (probably KSO_4) and the hot gas.

The desire to get practical operating experiences with any kind of MHD system will bring significant pressure from the technological community to implement this system.

Open Cycle MHD Base Load Systems

Worldwide interest seems to have focused on open cycle MHD generators topping steam systems but conflicting reports of Russian experience with a gas-fired pilot plant designed to produce 25 MW from MHD and 50 MW from the associated steam plant have strengthened a European mood of pessimism.

Research and Development Needs

A significant amount of applied research and practical development lies between current technology and successful utilization of MHD.

Coal Combustion. To utilize the large reserves of coal with at least 10 percent ash would require sophisticated combustion systems (probably multistage) that can provide a clean, pressurized, ultra-high temperature product. Low energy coal gasification techniques, modified for low hydrogen content because of the MHD electrical process, is an alternative. Air preheat development probably should be tied to the combustion system.

Channel Materials. Fundamental experience with both insulator and electrode materials in the high-temperature environment with associated electrical current flow and slag and seed contamination is crucial. Improved predictability of MHD channel performance when scaled to practical sizes is only truly useful with engineering materials so materials technology is the driving influence.

Seed Recovery and Gas Cleaning. A forcuitous match between seed fraction and coal sulfur content is viewed by some as important. Potassium carbonate seed seeks out the sulfur in the combustion products to become potassium sulfate, also an acceptable seed, so when the seed recovery process captures about 99 percent of the potassium to avoid an expensive seed loss, it also has captured the sulfur. Reconversion of the potassium sulfate to potassium carbonate, beneficiating the sulfur, is considered straightforward.

Increases of NO_x emissions to the level of 10,000 ppm are anticipated because of the high combustion temperature requirements. Satisfactory NO_x control techniques are considered beyond current and near-future technology.

Pilot-Plant Studies. Because of scaling problems, some authorities view the Russian work plan favorably as "...a gigantic experimental breadboard...(which) will give the Soviet Union an optimum experimental program".(W-64) Such evaluations are more easily rationalized than justified. In this paper(W-64) the author is highly critical of estimates of new exploration for sources of nuclear ore but assumes an assured fact the ability of the technological community to produce the advancements to make MHD practical. MHD development success is not an assured fact. Eventually pilot-plant studies will have to be considered in continued MHD research.

Other Variations. Nonsteady flow MHD channel systems may change some of the critical boundary conditions. Explosion driven and other shock wave systems have been investigated only far enough to illustrate technical possibility. At the moment these are only interesting side issues.

Anticipated Funding. The following tabulation is based on estimates including a pilot-plant program(W-64) at an aggressive optimum level.

	Through 1975	1980	1982
(Millions)	45	300	90

In the estimate, practical development would be completed in 1982 after a gross expenditure of $435 million for a pilot-plant program returning $20 million from the sale of power. A net cost of $282.5 million is estimated(W-64) allowing for residual worth of the plant, presumably as a production facility.

Environmental Burden. Optimistic assumptions(W-64, W-65) are that the bulk of the new installations of fossil fuel plants after 1985 could be open cycle MHD/steam plants assuming a slightly increasing role of fossil fuel as an electrical energy source and the necessity to retire obsolete plants.

The environmental emissions are all gains except for NO_x which could be as high as 10,000 ppm in the exhaust. Of the 10 percent ash entering with the fuel, at least 75 percent(W-63) will have to be removed in the combustion process before expansion through the MHD dust. Seed added at levels of 1 atom percent must be recovered at better than 95 percent efficiency(W-66) to avoid excessive seed costs.

That process will also collect other particulates in the exhaust. Subsequent seed treatment will remove the sulfur from the coal in the exhaust (if it was not already removed in a modified combustion process).

Thermal pollution should gain by an overall thermal efficiency gain from 40 percent to 50 percent. The heat rejection would be reduced from 60 percent of the thermal energy input to 50 percent.

Closed Cycle MHD Systems

In these systems, noble gases such as helium are heated, seeded, expanded through the MHD channel system, cooled by giving up heat to the bottoming steam plant (just as in open cycle), cooled in a regenerative heat exchanger, compressed, reheated by the regenerative heat exchanger, and recycled to the primary heat exchanger. The working fluid is sealed from outside contamination and loss.

The primary technological barrier to such a system is the primary heat exchanger. Steady flow equilibrium ionization of the plasma requires too high a gas well temperature for any known practical containment materials. Consequently, phenomenological variations that induce ionization at much lower source gas temperatures have been proposed. Nonequilibrium ionization procedures attempt to force local ionization and rely on the decay time to hold the electrical conductivity through the MHD duct extraction section. General results to date indicate that, even when the gas can be tricked into being adequately conductive, other practical aspects such as density are almost totally mismatched with practical needs for the rest of the system.

Some other concepts with shock waves(W-67, W-68) have been conceived and have shown preliminary laboratory feasibility but have not been extended to even bench-scale systems. Research along these lines could produce MHD/steam systems for application to high-temperature nuclear reactors where the gases on both sides of the heat exchanger are relatively noncorrosive. Extension of closed cycle operation to combustion products seems quite unlikely.

Research Experiments. Significant bench-scale experiments at a rate of $500,000/year through 1975 could establish the feasibility of such a system. Reduction to practice, however, would involve pilot-plant development at expenditures probably less than for open cycle systems in about the same time frame--pilot-plant operation in the early 1980's.

Environmental Burden. The primary impact would be an improvement in the heat rejection load of nuclear generation plants. If overall nuclear cycle efficiency can be increased from 32 percent for a representative light water reactor(W-65) to the neighborhood of 45 percent with an MHD finding new materials capable of high-temperature operation, and at improving the thermoelectric efficiency and general utility of known thermoelectric materials. Since 1962, the emphasis in thermoelectric-power generation research has shifted from materials development to hardware development. Improved electrical contacts, improved burners, and stronger and more chemically stable thermocouples have served to improve reliability, reduce weight, and bring actual generator efficiencies closer to theoretically possible values.

Thermoelectric generators have been built and operated satisfactorily in a variety of situations. They have been operated from heat sources fueled in many different ways, including butane, gasoline, kerosine, propane, JP-4, and fuel-oil burners; radioisotopes; and nuclear reactors.

A large majority of the thermoelectric generators that have been built have been in the subkilowatt range. Recently the U.S. Atomic Energy Commission has initiated an Isotope Kilowatt Program which has as its objective the production of 1 to 10 kw of electrical power for terrestrial and undersea applications.(W-71) One of the systems being evaluated is a radioisotope thermionic generator (RTG). This program has not yet progressed to the point where the "best system" has been identified.

Probably the next largest thermoelectric system presently under development is the multihundred watt RTG being developed for the space program and expected to "fly" in the mid-1970's.(W-72) Presently, the generator efficiency for the MHW-RTG is expected to be less than a percent. By incorporating a cascading concept, wherein two thermocouples are in series thermally so that heat rejected by the cold junction of the first-stage thermocouple is absorbed by the hot junction of the second-stage thermocouple, somewhat higher efficiencies, perhaps to nearly 9 percent, can be achieved.

Semiconductors materials used for thermoelectric applications often do not require the extreme care in preparation that material for devices such as transistors do. Thus, they may be somewhat less expensive. Even so the materials cost for thermoelectric elements is still so high that thermoelectric generators simply cannot compete economically with other conversion processes. Many experts feel that an order of magnitude improvement in figure of merit over those of the best present day materials would make thermoelectric power generation worthy of consideration for certain applications. There is presently no reason to believe that a materials breakthrough of this magnitude is likely to occur in the foreseeable future. Thus, thermoelectric-power generation is not suitable as an alternative method for large-scale power generation.

Thermionic Power

A thermionic conversion system consists of a heat source, a number of augmented gas-cooled reactor, the cooling energy released per unit of electrical energy produced is almost halved.

The effectiveness of MHD systems for meeting possible future demands for reduction of stack particulates and sulfur oxides should be considered high. The cost is inherent and buried within MHD development costs so the best cost to use would be that of MHD development. Oxide of nitrogen controls may be relatively ineffective. Since no practical effective technique has yet been demonstrated, it is difficult to anticipate the research costs. As an estimate, about 5 percent of the total pilot-plant program discussed earlier might be appropriate--$20 million between now and 1982.

Thermoelectric

A thermoelectric generator is a device in which a closed electrical circuit is made up by two dissimilar thermoelectric materials and a load. Current flows around the circuit when a temperature difference exists between the two ends of the thermoelectric materials. The efficiency of energy conversion depends upon the temperature difference (as in any thermal "engine"), the device geometry, and a factor involving the material properties alone. The material factors, called the "figures of merit", Z, is defined as $Z = \alpha^2 \sigma K^{-1}$, where is the Seebeck coefficient, σ is the electrical conductivity, and K is the thermal conductivity.

The quest for higher and higher efficiencies focuses on finding materials with higher values of Z. Since Z depends upon the temperature, maximum efficiency for a given material occurs within narrow temperature ranges.

Prior to 1947, only certain metals were known to exhibit relatively high Seebeck coefficients. Although the cost of these metals was low, the efficiencies of electrical power generators using them were only 1 percent at best. In 1947, an article which reviewed the state of thermoelectric-power generation at that time(W-67) showed that materials containing bismuth and antimony, tellurium compounds, and lead compounds could be used to achieve power-generation efficiencies of about 5 percent. During this same period, the gas-controls industry was conducting research on thermoelectric generators which could use the heat from gas burners and pilot lights to generate the power required to operate blower controls and automatic controls.(W-70)

The rapid growth in knowledge of semiconductor technology, such as: control of resistivity, control of purity, methods of materials preparation, which occurred with the advent of the transistor, along with requirements of the space program, led to heavy expenditures on research in all phases of thermoelectric power generation. From 1958 to 1962, the U.S. Navy Bureau of Ships sponsored many research programs aimed at thermionic diodes, power conditioning equipment, and ancillary temperature control equipment. Major attractive features of thermionic conversion systems are the absence of moving parts (which suggests potentially long service life), a very desirable power-to-weight ratio, and a good match between the thermal requirements of the diodes and the capabilities of fast nuclear reactors. These features have made thermionic power a good candidate for unattended, remote sites. Most developmental efforts have been directed toward the realization of systems for such applications.

The most advanced thermionic power generating systems so far developed have been assembled in the Soviet Union. They have operated thermionic reactor systems (TOPAZ I for 1500 hours, and TOPAZ II for 6,000 hours) at power generating levels of 5 to 10 kwe.(W-73) At the present time the only major U.S. thermionic program expects to operate a thermionic reactor system at 50 to 300 kwe power levels in 1978.(W-73)

Thermionic converters have as the basis of their operation the Edison effect, that is, the evaporation of electrons from hot bodies. The number of electrons which are able to escape by surmounting the potential barrier at the surface of the emitting body is an exponential function of the emitter temperature. Thus, on the face of it, the amount of current produced by the thermionic diode should increase rapidly as the emitter temperature is raised. This behavior would obtain except for the fact that the first electrons to enter the space surrounding the emitter exert, as a result of their like electrical charges, repulsive forces on additional electrons attempting to escape from the emitter. Through this process a space-charge cloud of electrons is built up in the space surrounding the emitter and the number of electrons then able to escape becomes comparatively small. In order to provide the high current densities necessary for reasonable efficiencies, some means of space-charge compensation must be provided.

It is possible to reduce the spacing between the emitting electrode and the collecting electrode to a small enough value so that space charge has very little effect upon diode performance. The spacings required, however, are extremely small, less than 0.001 inch, and the mechanical problems involved in such a scheme have led to abandonment of efforts to produce practical, close-spaced coverters.

The alternative method of space-charge compensation that has been almost universally adopted is the introduction of positive ions into the interelectrode space. The usual source of ions is cesium vapor. The ions can either be produced by surface ionization when cesium atoms come in contact with the hot emitter, or by volume ionization which occurs in the interelectrode space as a result of collisions between energetic electrons and cesium atoms. In practice it has been found that maximum diode efficiency is achieved when the ions are created by volume ionization, that is, when the converter is operating in the so-called arc mode.

As with other energy conversion systems, the efficiency of thermionic diodes increases as the emitter temperature is increased. At the present technology level there are few materials that can maintain mechanical integrity and hermeticity during atmospheric exposure at temperatures of 1500 C and above. Because of this, the major thermionic developmental programs have relied upon diode designs wherein the emitter--i.e., the hottest member--is enclosed in an evacuated space essentially free from oxygen. With such a design one of the obvious ways of providing the thermal energy to the emitter is to encase nuclear fuel within the body of the emitter and operate the diode within the core of a reactor. This concept represents the in-core thermionic power generator system. All of the continuing major developmental programs are based upon this concept.

Some attention has been given to out-of-core thermionic systems. A major accomplishment of these efforts has been the conception and development of the heat pipe. These devices have the ability to transport thermal energy over distances up to several feet with very little thermal loss and to concentrate the thermal flux received over a relatively large area and discharge it into a much smaller area. Small-scale fossil-fuel-fired thermionic systems have been developed, some of which utilize heat pipes and others of which expose the outer shell of the thermionic diode to the flame. Numerous materials problems remain to be solved for these systems and at present maximum diode life has been only a few hundred hours and even then the operating temperatures have been restricted to values where the conversion efficiency of the diodes is only about 10 percent.

One great disadvantage of thermionic converters is that they are low-voltage high-current devices with typical output voltages of 0.5 to 0.7 volt per cell. Thus, it is necessary to operate a great number of diodes in series in order to develop normal power-line voltages. Provisions must be made to bypass any cell that might fail in an open circuit mode and, because thermionic diodes produce direct current power, a substantial amount of power conditioning equipment will be required to produce power compatible with existing generating and transmitting systems.

Because of plasma losses, high-temperature materials problems, and lead losses brought about by the large currents produced in thermionic diodes, it does not appear that the device efficiency of practical thermionic diodes is likely to exceed 20 to 25 percent. This conclusion is in disagreement with that reached in Reference W-75 which assumes that eventually it will be possible to produce a collector with a work function of 1.0 eV. Experience has shown that evaporation products from the emitter deposit on the collector and inevitably lead to higher work functions after a short period of operation. Projected system efficiency of the U.S. system currently under development is of the order of 5 percent.(W-74)

The performance characteristics of thermionic diodes probably mean that they will find application as primary systems only when long, unattended service life, high power-to-weight ratio, or silent operation are more important than operating costs. On the other hand thermionic diodes have what is perhaps the unique ability to accept thermal energy at very high temperatures, up to 2000 C, and reject it at 600 C or above. This ability would appear to make thermionic conversion highly attractive as a "topping system" for some other primary system, especially if the heat source is a nuclear reactor.

The U.S. system presently under development is being supported by appropriation of a few million dollars annually. The present schedule calls for operation of a comparatively low power (40 we) developmental model in 1978.(W-73, W-74) There has been a great deal of slippage in scheduling on this program in the past, and some slippage probably can be anticipated in the future in the absence of increased funding. Realization of the space-oriented thermionic reactor will have little direct benefit toward development of a topping system for terrestrial applications. The technology presently exists for producing a thermionic topping unit. Some of the discontinued space power developmental programs appear to have laid much of the groundwork for such a system.

Thermionic diodes are not complicated devices and are not difficult to produce. Thus, they should not require a large capital outlay once a suitable system has been developed.

It appears that a demonstration in-core reactor system suitable for use as a topping unit could be developed by a program similar to the one now in progress for the space power generator. More detailed analysis of projected reactor characteristics will be necessary before a meaningful prediction of developmental costs can be attempted. By analogy to the space power program it seems likely that a small demonstration thermionic reactor capable of driving a conventional generator might be developed with an outlay of 20 million dollars over a period of 5 years. Out-of-core thermionic diodes, utilizing heat pipes, which would be suitable for demonstrating the feasibility of an out-of-core topping concept probably could be developed and evaluated for a small fraction of this amount.

Since they would be functioning as a topping unit for other generating systems, the thermionic diodes would not be expected to have any undesirable influence upon the environment. Since they would serve to increase the overall efficiency of the complete installation, their use should serve to reduce any undesirable aspects of the primary system.

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APPENDIX X

MISCELLANEOUS ENERGY SYSTEMS

Summary

Hydrogen energy (and a fuel cell total energy system utilizing hydrogen), space heating and insulation, energy storage, and waste heat recovery were examined for their influence on the environment. Generally, these systems have a favorable environmental burden: the combustion of hydrogen produces little or no burden; the use of insulation diminishes space-heating fuel emissions and conserves energy resources; energy storage, particularly as compressed gaseous fuel or as compressed air for turbine power, decreases the environmental burden; and waste heat recovery, where it is economically practical, diminishes the thermal pollution of streams and air.

The systems are qualitatively ranked as follows:

- Hydrogen energy
- Space heating and insulation
- Energy storage
- Waste heat recovery.

Hydrogen is a very versatile fuel which is capable of providing large quantities of electrical and other forms of energy including synthetic fuels. Until natural gas supplies or comparative costs make hydrogen economically competitive, the incentive to move swiftly toward a "hydrogen economy" is not present, and, therefore, it is unlikely that significant energy will be developed from this source through 1990.

The assault on the environment caused by producing hydrogen by coal gasification and hydrogen utilization to produce steam-electric power is considered to be less than conventional coal-steam-electric plants. Nuclear power-water electrolysis-produced hydrogen will have little more environmental burden than the LW nuclear electric plant itself except for the inefficiencies of electrolysis and reconversion of the hydrogen to electricity. An important consideration in utilization of hydrogen is that it will not contribute undesirable emissions at the point of utilization either as fuel for fuel-cells or for steam generation when electrolytically produced hydrogen and oxygen are used as the energy source.

Space heating consumes about 20 percent of the nation's energy. Environmental burden from air pollution emission can be effected by fuels, equipment design, equipment adjustments, and thermal insulation of the structures.

The analyses presented in this appendix for residential, commercial, and industrial space heating are based on simplified cases using average emission factors for different fuel-types in general classes of equipment. An important consideration that is masked by the use of averages is the wide difference in emission performance between different heating units within a class; in view of this factor, continued R&D effort is needed to establish criteria for the design, operation, and maintenance of combustion equipment for minimum emissions.

Improved thermal insulation is one of the most effective, simplest, economical, and immediate control measures for air pollution emissions from space heating--and an approach that can be implemented by individual home owners.

Hydro-pumped energy storage has proved to be the only practical system thus far developed to store large quantities of energy recovered from other systems, but its undesirable utilization of land as reservoirs is a decided deterrent to its widespread use.

The electrochemical storage of off-peak energy by means of water electrolysis-fuel cell combinations in which the hydrogen and oxygen are stored for later use, offer some attractive possibilities. Unlike hydro-pumped storage, electrochemical storage is not seriously site restrictive. When used in conjunction with nuclear plants, electrochemical storage of energy would tend to decrease the environmental burden as compared with pumped storage of fossil fueled plants.

Like natural gas, hydrogen may be stored as compressed gas or by liquefaction. Though this may be accomplished without serious aesthetic insult to the environment, the matter of leakage of hydrogen from underground storage and gaseous emissions associated with the combustion process associated with the compressor prime movers may contribute to the environmental burden.

Compressed air storage from gas turbine power generating equipment during off-peak loads for reuse during peak loads appears to be quite attractive. The gas turbine will produce only one-third of the combustion products as environmental burden since it is unnecessary to provide power to the compressor during the period when the compressed air storage is used. This system has not as yet been utilized extensively, however.

Waste heat is generally regarded as the heat rejected in power cycles, especially those associated with the generation of electricity. Waste heat recovery and its utilization to produce useful products, and thereby unburden the environment, hold very marginal promise economically. Financial incentives exist in the areas of climate control (particularly in community total energy systems), agriculture, and aquaculture. As higher priority is placed on the conservation of energy resources, a further enhancement of the benefits from waste heat recovery are to be expected.

Hydrogen Energy

There is little question but what fossil and nuclear-fission fuels will be the backbone of our energy sources in the United States for the remainder of this century. Controlled fusion is touted as being the utopian energy conversion system of the future but its many and difficult problems do place it quite into the future. As an intermediate fuel, hydrogen has much to offer:

- It can be produced in huge quantities relatively economically from various sources(X-1, X-2, X-3)
- It may be transported more economically than electricity(X-4, X-5)
- It is a low environmental pollution energy resource(X-6)
- In contrast to electric energy, it is readily storable(X-6)
- It may be put to a variety of uses either as a fuel for producing electricity or as a chemical base for a spectrum of synthetic chemical products(X-7, X-8).

Hydrogen, like deuterium and tritium for controlled fusion, is a utopian fuel, but the significant difference is that the technology for developing the "hydrogen economy" is well in hand.

Hydrogen as a fuel may be produced by gasification of coal, by electrolysis of water, and from methane and some solid wastes. It can be transported in underground pipelines much as our natural gas is today. For distances over 150 miles, hydrogen may be transported less expensively than electricity. The combustion of hydrogen emits no unburned fragments which are undesirable, although, when air is the oxidizer, NO_x is formed as with any conventional fuel. Aside from being used as a fuel, hydrogen can be the basic ingredient of many synthetic chemicals such as methane, methanol, ammonia, and ethylene.

The technology for bringing about the hydrogen economy exists. However, its cost in terms of equivalent energy is higher than natural gas today but it could well be competitive in the near future.

Hydrogen Production

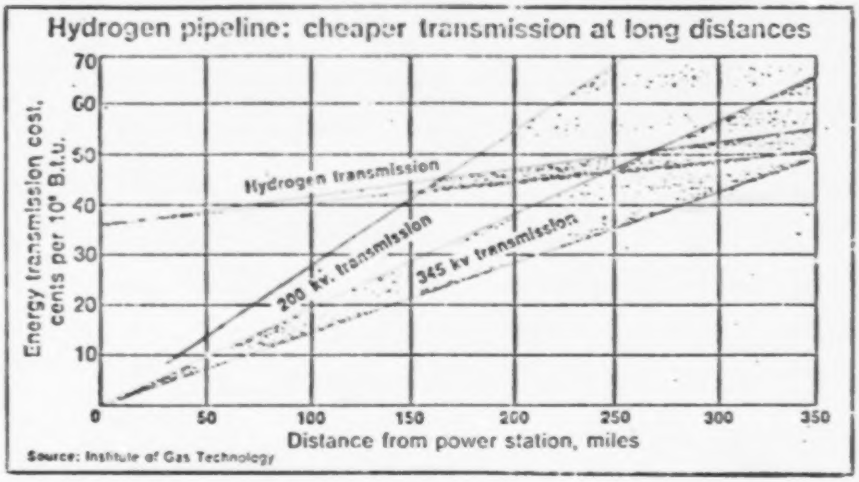
The science of producing hydrogen from the fossil fuels is as old as the significant demands for hydrogen which began at the turn of the century. By 1968, the United States was generating more than 2 trillion cubic feet of hydrogen annually, with a growth rate of about 18 percent per year.(X-9) Most was produced from natural gas, petroleum fractions, and off-gases from refineries. Although coke was used widely two decades ago for generating hydrogen by the water-gas process, little coke is gasified now. A strong trend is evident today to return to coal as the raw material for hydrogen generation as an intermediate in producing substitute natural gas. Several gasification schemes are now being investigated intensively, with a number in or approaching the pilot-plant stage.

The average price of hydrogen in 1968 was $0.25 per thousand cubic feet, with the selling price in 1970 for 95 percent hydrogen ranging from $0.20 to $0.60 per thousand cubic feet. The projected costs by 1990 will be between 22 and 30 cents per 1000 cubic feet.(X-4) Plant size is important, the cost decreasing rapidly up to capacities in the range of 20 million cubic feet per day. For lowest costs, plant output probably should lie between 50 and 250 million cubic feet daily. The production of hydrogen by electrolysis today costs about four times that from steam-reformed methane.(X-8) With the developments going on at the present time, it is expected that costs for producing hydrogen by electrolysis can be substantially reduced to the equivalent of 20 kwhr per pound of hydrogen with a capital outlay (for the electrolyzer) of $50 per pound of hydrogen per day.(X-1) Without doubt, the large quantities of hydrogen required tomorrow will come from fossil fuels. Electrolytically produced hydrogen from nuclear power may be a potential source in the future.

The efficiency with which coal can be converted into hydrogen depends greatly on the gasification system. Essentially all the older schemes are based on coke. Roughly 85 percent of the heat in the original coal to the coke oven is recovered as coke or useful by-products, but conversion of the coke to hydrogen will have an overall thermal efficiency ranging from about 50 percent to 80 percent. Hence, the overall efficiency from original coal to hydrogen could be as low as 30 percent. Such systems would be unattractive compared with present central-station power plants with their 40 percent overall efficiency from coal to electricity. Fortunately, gasification schemes are now being developed, such as the fluidized-bed gasifier, that have the potential for overall conversion efficiencies from coal to hydrogen of 75 percent with additional recovery of process heat as useful steam.

Hydrogen Transmission and Distribution

Analyses indicate(X-4, X-5) that hydrogen can be transported in pipelines for about one-third the cost of electricity and slightly higher than natural gas. The break-even point is for distances of 150 miles; above this distance, hydrogen has a distinct cost advantage as shown in Figure X-1. As the hydrogen pipeline will be underground, aesthetic problems associated with the electrical transmission towers and lines will be eliminated entirely. Distribution costs will be 4-1/2 times less than for electricity and slightly higher than for natural gas. The relative costs for production, transmission, and distribution for several energy systems are presented in Figure X-2. It will be noted that the coal gasification-to-hydrogen system offers the best overall cost attractions for energy produced and delivered to the utilization point. The costs for underground electrical transmission are about 90 percent greater than shown in Figure X-2.



Source: Institute of Gas Technology

FIGURE X-1. ENERGY TRANSMISSION COSTS

Hydrogen Energy Storage

Hydrogen, like natural gas, may be stored either as a liquid in tanks or as a gas in geologically appropriate spent natural gas wells. By way of comparison, the largest hydro-pumped storage system covers several acres and produces 15,000,000 kwhr of electrical energy. For a 50 percent conversion efficiency, a 90-foot spherical tank will contain the equivalent energy of liquid hydrogen.

Because of the variability of wind and tidal power, electricity produced from such sources may be converted into hydrogen and stored for later conversion electricity. The storage of hydrogen is presented in more detail in the section on Energy Storage in this Appendix.

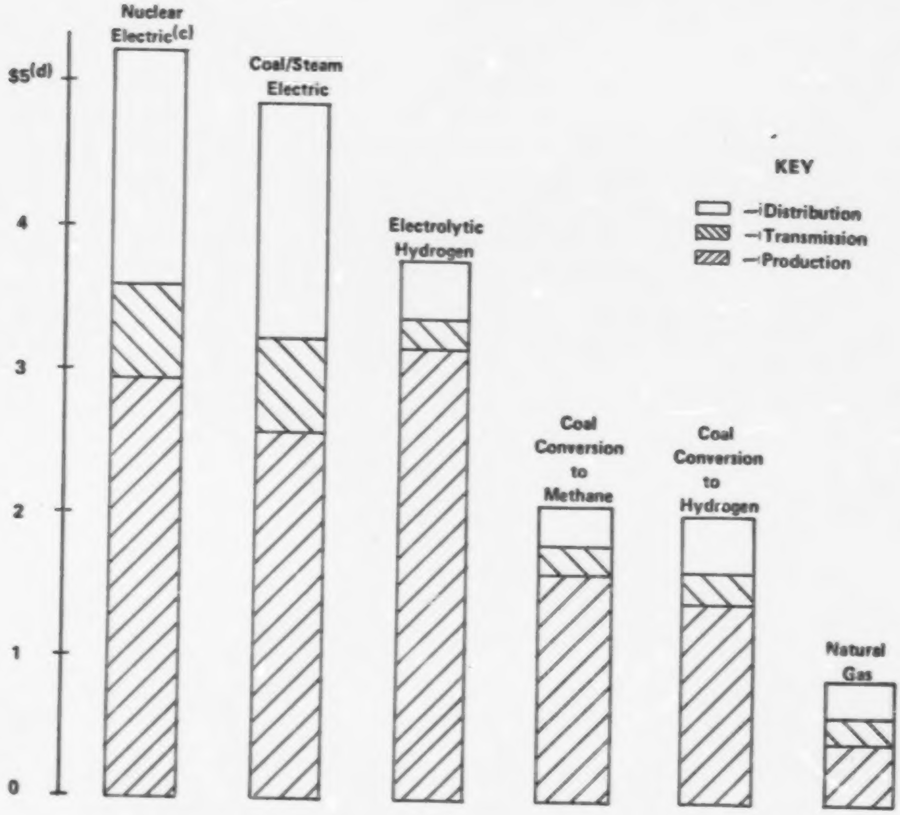


FIGURE X-2. RELATIVE COSTS OF ENERGY BY SYSTEM(a,b)

(a) Chemical and Engineering News (quoting Brookhaven National Laboratory), October 2, 1972, pg. 33.

(b) American Gas Association Monthly, June, 1972, pg. 8.

(c) Geographically location sensitive(a).

(d) Cost per million Btu; overhead electric transmission.

Environmental Burden (at Coal Gasifer Site)

The gasification plants, as long as it is consistent with water supply needs,(X-11) should be located as near as possible to the coal mine since it will be cheaper to move hydrogen than coal. Thus, any emission will be far from the urban areas in which energy is needed. Secondly, gasification plants inherently will emit less pollutants than power plants for at least three reasons: (1) sulfur in the coal will be converted to hydrogen sulfide which is easily removed from hydrogen; (2) no large-scale combustion systems are involved, so the NO_x production will be somewhat lower for a gasification plant; and (3) since there is no large volume of flue gas carrying off fly ash, there will be no output of particulate matter from the gasifier. Overall, therefore, a gasification plant should produce much less environmental burden than a coal-steam power plant. The gasification environmental burdens are discussed in the fossil-fuel gasification section of this report. Nonetheless, the water consumption for the gasifier plant is high and will have a regionally oriented impact on the environment.

If low-cost nuclear energy becomes available in large quantities with the location of nuclear reactors in remote sites where thermal pollution can be tolerated or utilized, hydrogen may be produced by electrolysis and transmitted through pipelines much more efficiently than electricity transmission, thereby unburdening local community environments (where the hydrogen is utilized) of nuclear reactor pollutants.

Hydrogen Utilization

Hydrogen is ideally suited for direct conversion into electricity in fuel cells. With a 53 percent efficiency of converting hydrogen to electricity at high loads, the overall system efficiency from coal to hydrogen to electricity would be about 40 percent. The waste heat from the fuel cells may be utilized for comfort control of living spaces. A suggested overall total energy system utilizing coal gasification to hydrogen, its transmission, and its distribution to urban-area fuel-cell substations is included as a supplement to this section.

Hydrogen could be utilized as a fuel in residences without venting insofar as carbon monoxide or carbon dioxide are concerned. Hydrogen could serve as an ideal industrial fuel as well as provide atmospheric protection in the ore and metallurgical processing of metals. Hydrogen is required in large quantities in converting coal into substitute natural gas.

There are proposals for using hydrogen for high-speed aircraft engine fuel. Hydrogen provides a good heat sink and extends the range of aircraft beyond that associated with JP-type liquid fuels. The projected costs of the two fuels break even in 1985(X-12). Of course, particulate and the gaseous emissions (with the exception of NO_x), associated with conventionally fueled aircraft engines will be eliminated by the use of hydrogen fuel. Liquid hydrogen for aircraft will pose special problems in handling, but these have been solved satisfactorily in rocket fueling systems.

There are also proposals to utilize hydrogen fuel for reciprocating engines,(X-13) gas turbines, and for ground transportation vehicles.(X-14, X-15)

Safety

One of the most important considerations in utilizing hydrogen is one of safety.(X-6) Those who are concerned about safety need to be convinced that hydrogen can be used without the disasterous explosions that occur with the use of natural gas which is less explosive than hydrogen. The technology exists for handling hydrogen safely and hydrogen rich methane gas has been used in the past in the United States safely. It is also being used in Italy as a fuel containing 80 percent hydrogen without difficulty.(X-4) Hydrogen dilution is suggested as a means for providing safety. Hydrogen enriched natural gas may be a viable means for the transition period from natural gas as hydrogen becomes the primary fuel.

One scheme, which is discussed in the supplement to this section, utilizes hydrogen in a fuel cell substation so that the hydrogen itself is not utilized within the residences or buildings being supplied with the electrical energy. If pure hydrogen is to be used with residences, explosion-proof switches, motors, and telephones may be necessary and this could increase construction costs by an estimated 10 percent.

From the foregoing it may be seen that hydrogen is indeed a versatile fuel and one which will produce a minimum impact on the environment at its point of utilization. It has the capability of supplying the large demands for clean energy which will be needed in the future.

It will allow the use of low-grade coal which will not otherwise be usable because of environmental considerations(X-4) but techniques for gasifying eastern coal still require development.

R&D Requirements

There are a variety of research needs. Chief among them are the production methodologies for low-cost hydrogen,(X-10) hydrogen transmission techniques, and the development of technical and safety standards for transporting, distributing, and utilizing hydrogen. There have been some 40 million dollars expended on coal gasification since 1964. Expenditures of the order of some 200 million may be needed by 1985 with an extra 100 million for the first production prototype plant.

Supplement on Total Energy System

Hydrogen Fuel Cell Total Energy System For Urban Communities. One application of fuel cells is to produce hydrogen in large quantities from coal as a typical energy source; to distribute that hydrogen by pipeline to 1-MW fuel-cell underground substations in urban areas intended to serve 40 homes grouped around the substation; to convert the hydrogen to electricity in conventional hydrogen-air fuel cells and distribute low-voltage direct current to the surrounding nearby homes by hollow copper conductors; and to pipe through those same conductors hot water provided by thermal losses in the substation systems. In this way, a large fraction of the chemical energy in the hydrogen can be converted into useful work with no effect on the environment in the urban area. Water is the sole reaction product from the fuel cells; the little waste heat produced in the substation can be utilized in the nearby homes. Any impact of the total system, then, will come in the remote area where the hydrogen is produced.

A city of 40,000 homes could be supplied with all its energy requirements by a thousand such substations. This equivalent 1,000 MW power system would consume approximately 4.8×10^8 cubic feet of H_2 per day at constant full-power output. Production of H_2 from coal by the most promising method should recover 75 percent of the heating value of the coal as H_2. This H_2, in turn, should be convertible to electricity with a system efficiency of at least 53 percent, so that the overall efficiency from coal to the energy used in the household should be 40 percent. Hence, the total impact on the environment will be comparable to conventional power generation but with all the environmental problems occurring at the H_2 plant and none in the urban area.

No data are in hand on the emission of pollutants from H_2 plants based on fluidized-bed gasifiers now under development of the kind envisioned here. Since the gasification step will convert sulfur in coal into H_2S, almost completely quantitative removal of sulfur can be achieved from the product H_2. There will be no emission of NO_x directly in the gasification step because no combustion takes place. The power plant supplying the gasification plant with electricity will emit pollutants like any conventional power plant. But since the amount of electricity required to run the gasification plant is not known as yet, the amount of pollutants emitted cannot be estimated. Roughly, if the electrical input amounted to 10 percent of the energy output of the gasification plant, the NO_x output would be about 10 tons per 1,000 MW per day. No appreciable quantity of particulates would be emitted, assuming that the power plant is equipped with electrostatic precipitators.

Overall thermal losses from coal to energy delivered to each residence would be about the same as for conventional power plants, since both systems have an overall thermal efficiency of 40 percent. The heat losses from the two systems, however, would be distributed differently with the fuel-cell system delivering most of its waste heat to homes where the thermal energy can be recovered usefully, whereas the central-station power plant discharges its waste heat into the environment.

The urban fuel-cell substation concept is at a very early stage of technical development. Present-day hydrogen-oxygen fuel cells are still much too expensive. Although operating satisfactorily in space missions and in other exotic applications, fuel cells need a large R&D effort to lower electrode costs and cell-assembly methods to meet the demands of commercial exploitation. In addition, the production of low-cost H_2 from coal and the development of pipelines specifically for H_2 transport will require additional R&D. Much of the basic research has been done already. Mainly needed now are the developmental work and systems studies that will result in a practical, low-cost, urban power system free of any emission of pollutants in the urban area. Full-scale installations should be feasible by 1985 at the latest.

Estimated Funding Effort and Requirements
($1000)

Expenditure to date, 1972	Expenditure for Each 5-Year Period Through				
	1975	1980	1985	1990	Beyond 1990
	$3,000	$5,000	$25,000	$25,000	?

Fuel-cell substations will completely eliminate pollution in urban areas if their energy source is hydrogen. Even waste heat will be conserved in the idealized system. As far as the urban area is concerned, pollution control will exceed all existing and anticipated regulations. Pollution will occur at the remote site where the H_2 is generated, but the amount emitted is expected to be small compared with emission from power plants of the same output. Roughly, pollution control of such a gasification plant probably will not cost more than $10 per kilowatt of generating capability at the fuel-cell substation.

Space Heating

This module describes the environmental burden of space heating applications as consumers of energy. The focus here is the air pollution impact of fossil-fuel combustion for space heating at point of use. The following considerations should be noted:

(a) Impacts of the energy supply and transportation are not covered in this module.

(b) Equivalent electrical energy requirements for electrical heating are identified so that electrical heating may be related to the impact of the electrical energy system, including that at the point of electrical generation and up-stream in the fuel supply circuit.

(c) Energy for water heating is not included, nor is cooling with direct fossil-fuel energy, which is relatively insignificant in volume.

Classes of space heating. Space heating is considered here in the following classes (although definitions of fuel user categories differ for various statistical records).

- *Residential* - single-family dwellings, small apartments, etc.
- *Small Commercial* - stores, apartments, small office buildings, etc.
- *Large Commercial and Industrial* - large office buildings, institutions, factories, warehouses, etc.

The burdens of these major classes of space heating are covered by separate approaches in this analysis.

Perspective of Space Heating in Overall Energy Consumption and Environmental Burden

Energy Consumption For Space Heating. Space heating is of major significance in the nation's energy consumption and is estimated to account for about 20 percent of U. S. energy consumption, or about 12,000 trillion Btu in 1968.(X-16) Water heating accounts for another 4 percent. These applications are broken down by sector as follows (in percent of U. S. consumption):

	Space Heating, %	Water Heating, %
Residential	11.0	2.9
Commercial	6.9	1.1
Industrial	2.1 est	.3 est
Total	20.0	4.3

Table X-1 shows a breakdown of energy consumption for space heating in residential, commercial, and industrial applications by fuel or energy source. Natural gas and oil share almost equally in dominating the residential and commercial space heating market, but electrical heating has grown in importance in recent years. Use of coal for residential space heating has dropped sharply since World War II but is still significant in some geographic areas.

TABLE X-1. ENERGY CONSUMPTION FOR SPACE HEATING IN U. S. BY FUEL AND SECTOR, 1968(X-16)

	Trillions of Btu			
	Residential	Commercial	Industrial	All Space Heating
Natural Gas	3,236	1,209	560[a]	5,005
Petroleum Products	2,988	2,405	340[a]	5,733
Coal	(b)	568	370[a]	938
Electricity	451	(b)	Nil est	451
All Energy	6,675	4,182	1,270	12,127

(a) Not identified in source study but apportioned here according to fossil fuel consumption for all uses in Industrial Sector.

(b) Assumed "nil" in allocations by source study,(X-16) but use is significant in some geographic areas.

Environmental Burden of Space Heating

Table X-2 shows the relative contribution of residential and commercial space heating and industrial steam generation to all air pollutant emissions from combustion for energy conversion.(X-17) In this framework, pollutants of principal significance in space heating are

- particulates
- NO_x
- SO_x

TABLE X-2. EMISSIONS FROM RESIDENTIAL AND COMMERCIAL SPACE HEATING AND INDUSTRIAL STEAM GENERATION(X-17)

	Contribution of Nationwide ECC Emissions,[a] percent		
Pollutant	Commercial & Residential Heating	Industrial Steam Generation	Total
Products of Incomplete Combustion			
Combustible Particulate	9	36	45
CO	1	nil	1
Gaseous HC	1	<1	1
NO_x	5	12	17
Fuel Contaminants			
SO_x	12	19	31
Ash (Noncombustible Particulate)	4	21	25

(a) Emissions by combustion for energy conversion processes.

The term "thermal pollution" is not really applicable in space heating because all the heat energy ultimately is absorbed by the atmosphere; however, heat lost in flue gases is not useful energy.

Table X-3 provides a breakdown by major fuel classes for emissions on a tons/year basis covering: (a) residential and commercial space heating, and (b) industrial steam generation.(X-17)

TABLE X-3. EMISSIONS FROM RESIDENTIAL AND COMMERCIAL SPACE HEATING AND INDUSTRIAL STEAM GENERATION(X-17)

	Emissions, $10^{(6)}$ tons per year					
	Commercial & Residential Space Heating			Industrial Steam Generation		
Pollutants	Coal	Oil	Gas	Coal	Oil	Gas
Products of Incomplete Combustion						
Combustible Particulate	0.10	0.11	0.07	0.57	0.04	0.08
CO	0.43	0.03	<.01	0.12	0.01	<.01
HC	0.09	0.04	n	0.06	0.01	0.02
NO_x	0.07	0.64	0.38	0.93	0.33	0.65
Fuel Contaminants						
SO_x	0.85	1.2	n	3.71	1.07	<.01
Ash	0.12	0.08	n	0.66	0.03	n

n, emission considered negligible.

Approaches to Emission Control for Space Heating

Emission controls applicable to residential and commercial space heating equipment are relatively limited, and not all options are universally available. Control approaches can be classified as follows:

- Fuel switching
  - -- shifting to a cleaner burning fuel (coal to gas, or to electrical heating if only the point of use is considered)
- Replacement of outmoded and poor operating equipment with modern units
- Improve burner adjustment and maintenance
  - --tuning for efficiency and minimum emissions as the simplest form of "combustion modification".
- Reductions in energy requirements for fuel conservation
  - -- improved thermal insulation
  - -- temperature control setback at night or during unoccupied periods

-- heat recovery of internal loads

For large commercial and industrial boilers, additional emission controls can be applicable in the form of various combustion modifications or of stack cleanup processes (i.e. cyclones, precipitators, or scrubbers). However, these controls are not practical or economical for the major portion of the nation's space heating load.

Analysis of Emissions From Residential Heating

Table X-4 shows the fuels and types of residential heating equipment as determined by the 1970 Census of Housing.(X-18) Nearly 70 percent of U.S. homes have central systems or built-in systems. For purposes of this analysis, a "typical" single-family dwelling with a control or built-in system was assumed, and estimates of the relative air-pollutant emissions impact were made for heating this unit with electricity, gas, oil, and coal.

TABLE X-4. INVENTORY OF HEATING EQUIPMENT AND FUELS FOR RESIDENTIAL SPACE HEATING IN THE UNITED STATES (1970 Census of Housing)

Million Housing Units,	Heating Equipment for Year Around Housing Units
13.82	Steam or Hot Water
28.77	Warm Air Furnace
3.52	Built in Electric Units
5.88	Floor Wall or Pipeless Furnace
3.30	Room Heaters with Flue
3.95	Room Heaters without Flue
	Fireplaces, Stoves, or Portable Heaters
0.58	None
Million Housing Units,	**House Heating Fuels for Occupied Housing Units**
35.01	Utility Gas
16.47	Fuel Oil
1.82	Coal or Coke
0.79	Wood
4.88	Electricity
3.81	Bottled, Tank, or LP Gas
0.27	Other
0.40	None

"Typical Residences"

A typical single-family residence is assumed here as having 1500 square feet, built to FHA specification,(X-19) and located in Washington, D.C. (where the climate is similar to that at the center of the U.S. population, near St. Louis, Missouri, in degree days).

Cases

Three cases were assumed as follows to reveal the effect of combustion equipment tuning by frequent and competent servicing, plus the effect of increasing thermal insulation.

Residential Case	Combustion Equipment Tuning	Thermal Insulation
I	Average	Approx. FHA specs
II	Well-tuned	Approx. FHA specs
III	Well-tuned	Approx. FHA specs and additional insulation and storm windows

With emission estimates for the various fuels for these 3 cases, the impact of different mixes can be estimated on a national basis, including fuel-use patterns, service, and degree of insulation.

Efficiencies and Emission Factors

Table X-5 shows the overall seasonal efficiencies and emission factors used in the estimates. Seasonal efficiencies are based on the ASHRAE Guide(X-20) plus Battelle's judgment. Emission factors are based on EPA published factors(X-21) and on Battelle field measurements of emissions from residential heating units.(X-22)

Analysis of the Three Residential Cases

Table X-6, -7, and -8 provide a summary of the three residential cases.

Summary of the Residential Cases for Particulate

The effect of the three cases on particulate emissions, one of the significant pollutants, can be seen as follows:

Case	Particulate Emission, lb/year		
	Gas	Oil	Coal
I Average Adjustment	0.8	2.6	155
II Well-tuned	0.7	2.4	155
III Well-tuned plus additional insulation	0.3	0.9	56.6

TABLE X-5. EFFICIENCIES AND EMISSION FACTORS USED IN RESIDENTIAL AND COMMERCIAL ANALYSIS

Fuel	Unit Efficiency, percent	Emission Factor Units	Pollutant Emission Factors				
			Particulate	CO	HC	NO_x	SO_2
Gas	65	lb/10^6 cu ft	5.(c)	20	5(c)	80(c)	0.6
Gas - well tuned	70	Ditto	5(c)	15	4(c)	80(c)	0.6
Oil	65	lb/1000 gal	2.4(c)	7.8(c)	0.7(c)	19.5 (c)	38 (a,c)
Oil - well tuned	70	Ditto	2.4(c)	4.3(c)	0.6(c)	19.5 (c)	38 (a,c)
Coal	50	lb/ton	20	90	20	3	57 (b)

(a) Based on 0.3 percent S in oil.
(b) Based on 1.5 percent S in coal.
(c) Based on Battelle studies.(X-22)

The principal improvement in emission levels is in switching from coal to either oil or gas as the fuel source. The reduction in emission upon switching from oil to gas is about the same as obtained by reducing the energy requirements by improved insulation, which is applicable to many homes. As expected, lowest emissions are obtained from gas-fired units in well-insulated residences.

Analysis of Emissions From Small Commercial Space Heating

The number of variables in commercial building configuration and construction is great and geographical differences are considerable. Hence, a simplified analysis is necessary to show directional effects in the air pollution impact of commercial heating variables.

The analysis of the small commercial class of space heating was developed on a square footage basis by assuming a structure typical of a store or other commercial establishment in a climate like Washington, D.C.

Assumed Structure

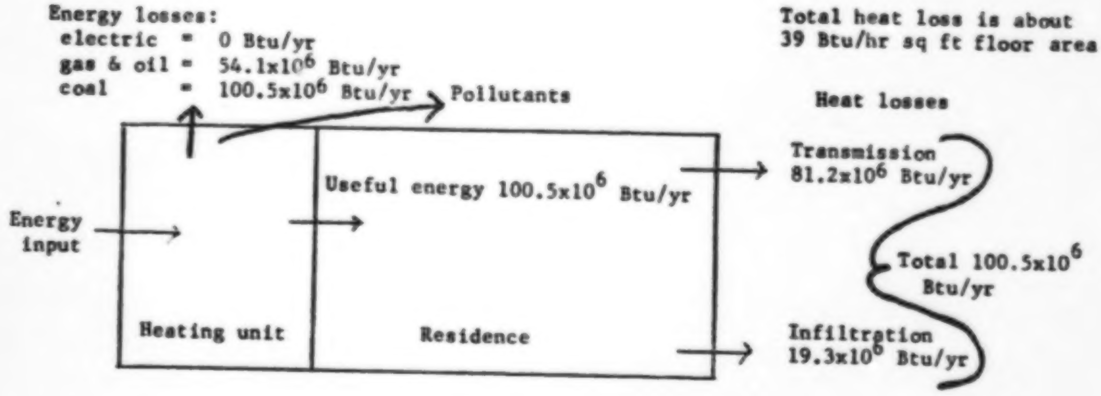
For Commercial Case I, a typical commercial structure was assumed to have a heat loss of 26 Btu/hr design heat loss per square foot of floor area. For Case II, improved thermal performance by insulation and

TABLE X-6. RESIDENTIAL CASE I

Assumptions: 1500 sq ft house in Washington, D. C. built to FHA specifications (The U.S. Energy Problem, Vol. 1)

Heating unit efficiency:

electric	100%
gas	65%
oil	65%
coal	50%


Energy losses:
electric = 0 Btu/yr
gas & oil = 54.1x10^6 Btu/yr
coal = 100.5x10^6 Btu/yr
Pollutants
Total heat loss is about 39 Btu/hr sq ft floor area
Heat losses
Energy input
Useful energy 100.5x10^6 Btu/yr
Heating unit
Residence
Transmission 81.2x10^6 Btu/yr
Total 100.5x10^6 Btu/yr
Infiltration 19.3x10^6 Btu/yr

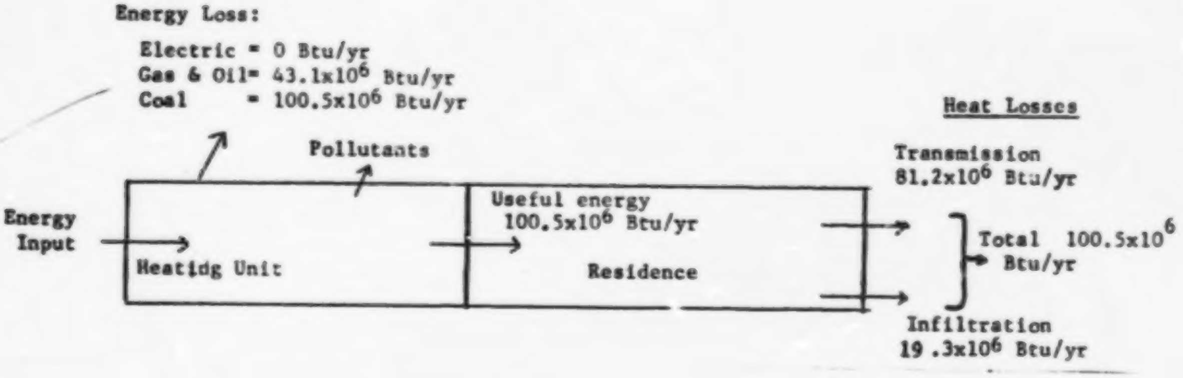
Form of Energy Input	Energy Input (Units/yr)	Energy Losses (Btu/yr)	Pollutants (lb/yr)				
			Particulate	CO	HC	NO_x	SO_2
Electric $\left(\frac{3413\ \text{Btu}}{\text{Kw hr}}\right)$	29,400 Kw hr/yr (100.5×10^6 Btu/yr)	0	0	0	0	0	0
Gas $\left(\frac{1000\ \text{Btu}}{\text{cu ft}}\right)$	154.6×10^3 cu ft/yr (154.6×10^6 Btu/yr)	54.1×10^6	0.8	3.1	0.8	12.3	0.09
Oil $\left(\frac{145{,}000\ \text{Btu}}{\text{gal}}\right)$	1070 gal/yr (154.6×10^6 Btu/yr)	54.1×10^6	2.6	8.3	0.7	20.9	40.7
Coal $\left(\frac{13{,}000\ \text{Btu}}{\text{lb}}\right)$	15,500 lb/yr (201×10^6 Btu/yr)	100.5×10^6	155	698	155	23.3	442

TABLE X-7. RESIDENTIAL CASE II

Assumptions: 1500 sq ft house in Washington D.C. built to FHA specifications ("The U.S. Energy Problem", Vol I)
Well-tuned heating unit

Heating unit efficiency:	
Electric	100%
Gas	70%
Oil	70%
Coal	50%

Cost of tuning:	
Electric -	$0/yr
Gas	$10/yr
Oil	$30/yr
Coal	Not effective


Energy Loss:
Electric = 0 Btu/yr
Gas & Oil= 43.1x10⁶ Btu/yr
Coal = 100.5x10⁶ Btu/yr
Pollutants
Energy Input
Heating Unit
Useful energy 100.5x10⁶ Btu/yr
Residence
Heat Losses
Transmission 81.2x10⁶ Btu/yr
Total 100.5x10⁶ Btu/yr
Infiltration 19.3x10⁶ Btu/yr

Form of Energy Input	Energy Input (units/yr)	Energy Losses (Btu/yr)	Pollutants (lb/yr) Particulate	CO	HC	NO_x	SO_2
Electric $\left(\frac{3413\ \text{Btu}}{\text{KWHR}}\right)$	29,400 KW hr/yr (100.5x10^6 Btu/yr)	0	0	0	0	0	0
Gas $\left(\frac{1000\ \text{Btu}}{\text{cu ft}}\right)$	143.6x10^3 cu ft/yr (143.6x10^6 Btu/yr)	43.1x10^6	0.7	2.2	0.6	11.5	0.09
Oil $\left(\frac{145{,}000\ \text{Btu}}{\text{gal}}\right)$	990 gal/yr (143.6x10^6 Btu/yr)	43.1x10^6	2.4	4.3	0.6	19.3	37.6
Coal $\left(\frac{13{,}000\ \text{Btu}}{\text{lb}}\right)$	15,500 lb/yr (201x10^6 Btu/yr)	100.5x10^6	155	698	155	23.3	442

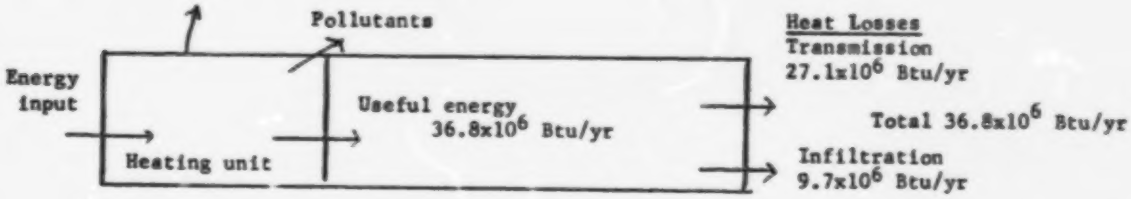
TABLE X-8. RESIDENTIAL CASE III

Assumptions: 1500 sq ft house in Washington, D.C.
Well insulated plus storm windows
("The U.S. Energy Problem", Vol I)

Storm windows: reduce infiltration losses by 50% at cost of $2000
Insulation: reduces transmission losses by 67% at cost of $690
Heating unit efficiency = electric 100%
gas 70%
oil 70%
coal 50%

Heating unit receives regular service of cost of $30/yr oil
$10/yr gas
Service not shown effective in reducing emissions from coal-fired units

Energy loss:
Electric = 0 Btu/yr
Gas & oil = 15.8×10^6 Btu/yr
Coal = 36.8×10^6 Btu/yr


Pollutants
Energy input
Heating unit
Useful energy
36.8×10^6 Btu/yr
Heat Losses
Transmission
27.1×10^6 Btu/yr
Total 36.8×10^6 Btu/yr
Infiltration
9.7×10^6 Btu/yr

Form of Energy Input	Energy Input (Units/yr)	Energy Losses (Btu/yr)	Pollutants (lb/yr) Partilate	CO	HC	NO_x	SO_2
Electric	10,800 KWhr/yr (36.8×10^6 Btu/hr	0	0	0	0	0	0
Gas	52.6×10^3 cu ft (52.6×10^6 Btu/hr)	15.8×10^6	0.3	0.8	0.2	4.2	0.03
Oil	363 gal/yr (52.6×10^6 Btu/yr	15.8×10^6	0.9	1.6	0.2	7.1	13.8
Coal	5660 lb/yr (73.6×10^6 Btu/yr	36.8×10^6	56.6	255	56.6	8.5	161

glazing was assumed to reduce the heat loss to 16 Btu/hr per square foot.

Analysis of the Commercial Cases

Tables X-9 and -10 provide a summary of the two commercial cases, using emission factors for well-tuned residential heating equipment from Table X-5. Efficiencies were assumed to be 75 percent; this is higher than for residential units because higher efficiencies can normally be expected from larger equipment. Coal firing was not included in the commercial cases because it was generally precluded from use in small commercial buildings due to operating labor and maintenance costs.

For commercial structures, there are additional avenues for energy savings beyond improved thermal insulation. These include heat recovery of internal loads that would otherwise be lost, like refrigeration condenser heat for grocery stores. Where the period of occupancy is limited, some savings can be achieved by control-point setback during unoccupied periods. These savings will depend on individual cases.

Analysis of Emissions From Large Commercial and Industrial Space Heating

Large commercial and industrial space heating is almost entirely by boilers supplying steam or hot-water systems, although these boilers may also supply steam for other purposes like industrial processes, absorption cooling, or on-site power.

Package firetube boilers are most prevalent in sizes up to about 500 boiler horsepower (16×10^6 Btu/hr output), frequently with dual-fuel capability firing either gas or oil; many are capable of automatic unattended operation. Larger sizes are mostly watertube-type boilers and are available to fire gas, oil, or coal (some with multiple fuel capability). Coal firing with stokers is more common in the larger sizes where a fulltime attendant is available.

Basis for Analysis

Table X-11 shows overall efficiencies and emission factors assumed for space heating using typical commercial-industrial boilers. The emission factors are based on EPA published factor(X-21) and Battelle studies on commercial boilers.(X-22) The analysis for this class of space heating is based on emissions per 10^9 Btu output (or energy deliverable for space heating). Coal firing was assumed to be with stokers for commercial-industrial boilers, because pulverized coal firing is seldom used except in very large industrial boilers or in utility boilers.

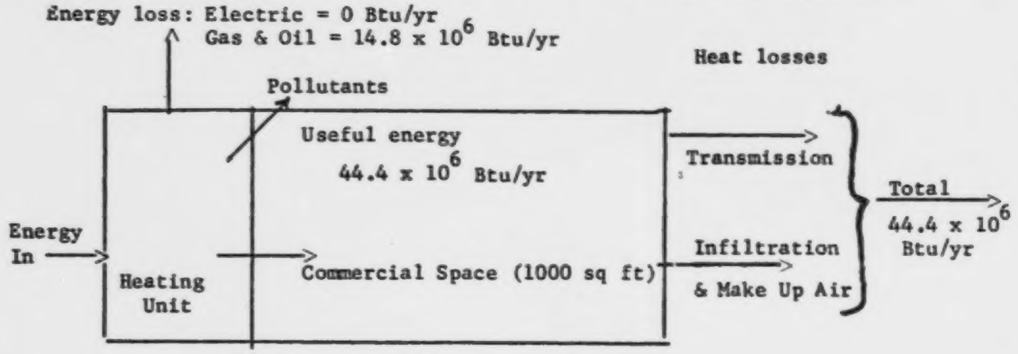
Analysis of Commercial - Industrial Case

Table X-12 summarizes air-pollution emissions based on the assumptions

TABLE X-9. COMMERCIAL CASE I.

Energy Requirements and Emissions
Based on Unit of 1000 sq ft Floor Area
and Washington, D.C. Location

Heating unit efficiency:	Electric	100%
	Gas	75%
	Oil	75%
	Coal - not suitable to this application	


Energy loss: Electric = 0 Btu/yr
Gas & Oil = 14.8 x 10^6 Btu/yr
Heat losses
Pollutants
Useful energy
44.4 x 10^6 Btu/yr
Transmission
Total
44.4 x 10^6 Btu/yr
Energy In
Infiltration & Make Up Air
Heating Unit
Commercial Space (1000 sq ft)

Total Heat Losses: Assume 26 Btu/hr sq ft at design condition

$$= \frac{26 \frac{\text{Btu}}{\text{hr sq ft}} \times 1000 \text{ sq ft}}{65\text{ F}} \times 4626 \text{ degree days} \times 24 \text{ hour/day}$$

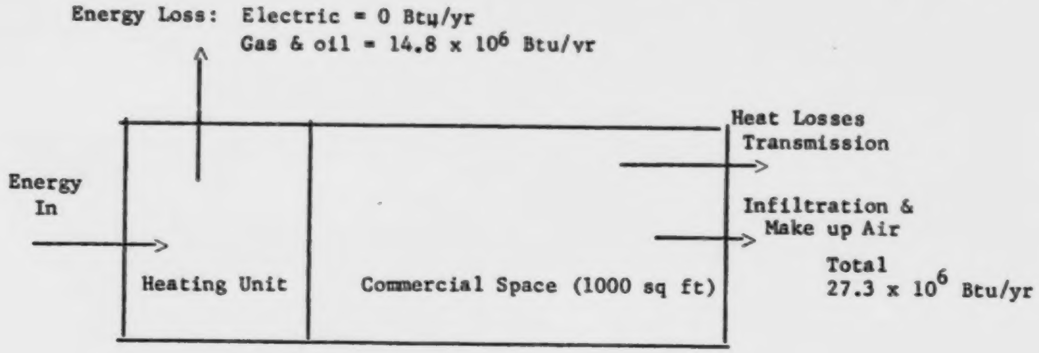
$$= 44{,}400{,}000 \text{ Btu/yr}$$

Form of Energy	Energy Input Units/yr	Energy Loss Btu/yr	Pollutants (lb/yr) Particulate	CO	HC	NO_x	SO_2
Electric	13,000 kw hr/yr (44.4×10^6 Btu/yr)	0	0	0	0	0	0
Gas	59.2×10^3 cu ft (59.2×10^6 Btu/yr)	14.8×10^6	0.3	0.9	0.24	4.7	0.04
Oil	410 gal/yr (59.2×10^6 Btu/yr	14.8×10^6	1.0	1.8	0.24	8.0	15.6

TABLE X-10. COMMERCIAL CASE II

Same as Commercial I

Except for Improved Insulation and Infiltration Loss
and Washington, D. C. Location


Energy Loss: Electric = 0 Btu/yr
Gas & oil = 14.8 x 10⁶ Btu/yr
Heat Losses
Transmission
Energy
In
Infiltration &
Make up Air
Total
27.3 x 10⁶ Btu/yr
Heating Unit
Commercial Space (1000 sq ft)

Total Heat Losses: 16 Btu/sq ft · Hr at design condition

$$= \frac{16 \times 1000}{65} \times 4626 \times 24$$

$$= 27{,}300{,}000 \text{ Btu/yr}$$

Form of Energy	Energy Input, Units/yr	Energy Loss, Btu/yr	Pollutants (lb/yr)				
			Particulate	CO	HC	NO_x	SO_2
Electric	8000 kw hr/yr (27.3×10^6 Btu/yr)	0	0	0	0	0	0
Gas	36.4×10^3 cu ft (36.4×10^6 Btu/yr)	9.1×10^6	0.2	0.5	0.15	2.9	0.02
Oil	251 gal/yr (36.4×10^6 Btu/yr)	9.1×10^6	0.6	1.1	0.15	4.9	9.5

in Table X-11 for different types of fuels.

It should be noted that there are wide differences between grades of oil within the residual oil classification (e.g. No. 4, 5, and 6 grades), resulting in wide differences in emissions.(X-22) These differences are especially observed in the case of particulate and in NO_x where the range of fuel-bound nitrogen is broad. The new "low-sulfur residual oils" (generally containing 1.0 percent sulfur) which are replacing conventional No. 6 oils have viscosity and other burning characteristics which place them toward the lighter grades of residual oil; their emission performance is also more like a No. 4 or light No. 5 oil.

Emission Controls

Other than by fuel selection, applicable emission controls for this class of equipment are generally in the area of improved adjustments of combustion parameters or of combustion modification; combustion modifications like staged combustion, or flue-gas recirculation are most effective in NO_x control. (It should be noted that individual differences between different burner and boiler designs are broad, and attention to equipment design criteria is important to emission performance. Such differences often go unnoticed in compilations of average emissions used for inventory purposes as in Table X-11.)

For coal firing, particulate control devices are sometimes installed in the stack. These include cyclones, electrostatic precipitators, baghouses, and scrubbers--with the first two types being most prevalent; a 75 percent removal efficiency is common and is assumed in the footnote comment in Table X-12. SO_2 stack gas control processes are not yet commercially used for this class of equipment; their introduction will depend on practicability and costs of the system and probably will follow their successful use on utility size boilers.

Insulation for Energy Conservation in Space Heating

Improving thermal performance of building construction by insulation is one of the simplest and most universally applicable methods of reducing air pollution by reducing energy requirements for space heating and cooling. With added impetus in view of the overall energy crisis, this approach is receiving widespread attention by government agencies(X-9, X-23) and by industrial groups. Architects and engineers are urging greater consideration to building design that will minimize energy requirements.(X-24, X-25)

Many homes and other buildings have low levels of insulation, or no special provision for insulation. Even modest additions of insulation can reduce heat losses for space heating by substantial amounts. The most economical and effective location for adding insulation is in

TABLE X-11. EMISSION FACTORS AND EFFICIENCIES ASSUMED FOR INDUSTRIAL SPACE HEATING

Fuel	Efficiency	Pollutant Emission Factors					
		Emission Units	Particulate	CO	HC	NO_x	SO_2
Gas	75	lb/10^6 cu ft(e)	6	13	0.6	45	0.6
Dist. oil	75	lb/1000 gal(e)	2	0.5	0.2	20	43(a)
Resid. oil	75	lb/1000 gal(e)	12	0.9	0.3	60	157(b)
Stoker Coal	65	lb/ton(f)	20(d)	10	0.2	6	57(c)

(a) Based on 0.3% Sulfur in No. 2 oil
(b) Based on 1.0% Sulfur in residual oil
(c) Based on 1.5% Sulfur in coal
(d) Based on 10% Ash in coal
(e) Based on Battelle studies (Reference X-8) except SO_2 which is based on (f)
(f) Based on EPA Emission Factors

ceilings where heat losses can be high and costs of insulation relatively low per unit area.

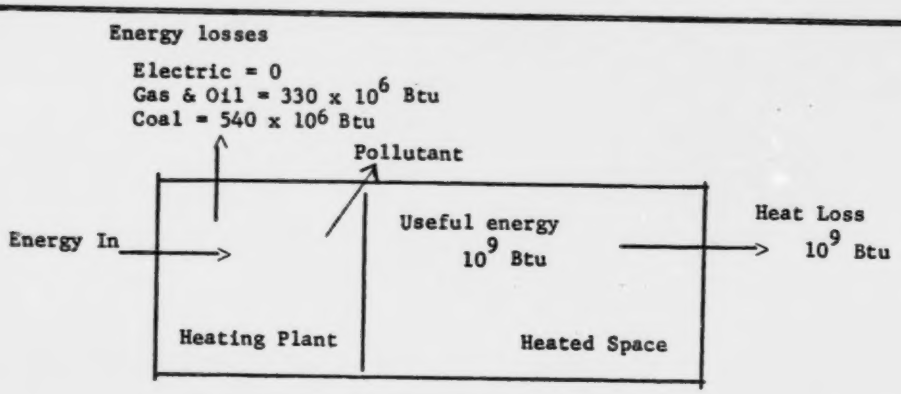
Insulation is most economically installed during initial construction, but insulation can be added to almost any home and to many commercial buildings, especially roof decks. Storm windows or other double glazing, plus weather stripping, can also be added to existing buildings, with important savings in heat losses both by conduction and by infiltration.

Insulation Standards. In response to President Nixon's energy message to Congress on February 8, 1972, insulation levels required in the FHA Minimum Property Standards have been tightened to cut maximum permissible heat loss by 40 percent.(X-26)

In terms of "U"-value (heat loss in Btu/hr-ft^2-deg F) an uninsulated wood frame wall gives a "U"-value of 0.22. This can be reduced to 0.05 with full insulation in the frame wall. The new FHA Standards for home construction are as follows:

	"U"-Value
Ceilings	0.05 to 0.08
Walls	0.07 to 0.17
Floors	0.08 to .24

TABLE X-12. COMMERCIAL-INDUSTRIAL CASE


Energy losses
Electric = 0
Gas & Oil = 330 x 10^6 Btu
Coal = 540 x 10^6 Btu
Pollutant
Energy In
Useful energy
10^9 Btu
Heat Loss
10^9 Btu
Heating Plant
Heated Space

Calculations on basis on 10^9 Btu delivered to heated space

Form of Energy Used	Energy in (units/10^6 Btu delivered to heater space	Energy Losses (Btu/10^6 Btu Delivered)	Uncontrolled Pollutant Emissions (lb/10^9 Btu delivered) Particulate	CO	HC	NO_x	SO_2
Electrical	293,000 kw hr (1000 x 10^6 Btu)	0	0	0	0	0	0
Gas	1.33 x 10^6 cu ft (1330.x 10^6 Btu)	330 x 10^6	8.0	17.	0.81	60.	0.8
Dist. Fuel Oil	9200 gal (1330. x 10^6 Btu)	330 x 10^6	18.4	4.6	1.8	184.	396.
Residual Fuel Oil	9200 gal (1330. x 10^6 Btu)	330 x 10^6	110.	8.3	2.8	552.	1450.
Stoker Coal	118,500 lb (1540. x 10^6 Btu)	540 x 10^6	1190.[a]	593.	11.9	356.	3380.

[a] This emission could be reduced to 300 lb with control equipment of moderate efficiency.

Some industry groups are calling for even tighter standards and are launching campaigns for increased insulation in new construction and for installation of added insulation in existing structures.(X-27) The economic payback in fuel savings is relatively short term (2 to 3 years), and the potential saving in total energy requirements is substantial.

Energy Conservation and Environment Burden. With "reasonably attainable" levels of insulation, energy conservation in residential construction has been estimated to be 1500 trillion Btu by 1982, or about 14 percent of the projected residential usage for space heating and cooling.(X-27)

This would be achieved if (1) 3/4 of new residential units in the decade have proper thermal treatment, (2) 1/4 of the existing single family homes are upgraded in insulation, and (3) 1/8 of all single-family homes add storm windows and doors. In consumer savings, this would amount to 17.2 billion dollars over the next decade. Potential improvements are even greater if more homes are upgraded.

The reduction in air pollution burden of space heating is roughly proportional to energy savings from improved thermal performance.

This is an area where there can be effective EPA answers to the citizen's question "What can I do to help in environmental protection?"

Energy Storage Systems

Hydro-Pumped Storage

Pumped storage has turned out to be the only practical way of utilizing off-peak power at a later peak-demand period. Combination pump-turbines move water from a low elevation to a higher one during periods of low demand for electricity, and then utilize this head to provide electricity whenever demand exceeds normal generating capacity.

Environmental Burdens. The main objection to pumped storage comes from local residents who dislike the appearance of storage reservoirs where there may be a difference of 75 to 100 feet in the water level between full and empty. In some places, as in a Colorado installation, the upper pool is in a remote area. But, as has occurred in New York, local residents have succeeded in blocking a pumped-storage system almost entirely for aesthetic reasons.

Other than appearance, a pumped storage system can have a minor impact on the local environment because it forms a huge pond with a variable shoreline. More importantly, since about 4 kwhr input as pumping power to a storage pond produces only 3 kwhr output, there is a net loss of 1 kwhr for every 3 kwhr recovered. (One source(X-28) suggests an even poorer efficiency; 3 kwhr of pumping for each 2 kwhr of energy generated.) If the input energy is provided by a full-powered steam plant, then the total emission of pollutants increases 33 percent for that fraction of the energy that is stored. On this basis, for each 1,000 MW day of recovered electricity, the environmental burden would be 1.3 times that of the generating plant.

Restrictions on the further use of pumped storage will be for aesthetic rather than technical reasons. Presently operating pumped-storage plants have demonstrated the practicality of this system of energy storage. The required head between upper and lower pools and the design of the turbine pumps have been evaluated thoroughly, as well as the economic factors influencing the size and the location of pumped-storage systems. No further R&D is required, the future extent of pumped storage being fixed mostly by geographical considerations and by economic factors influencing the ratio between base load and swinging load generating plants.

Electrochemical Storage

Electrochemical storage of off-peak energy might be used in a manner similar to pumped hydro storage. Conventional storage batteries, advanced battery concepts, and water electrolysis-fuel cell combinations (with storage of hydrogen and oxygen gas) are being considered for use by the electric utility industry. Electrochemical energy storage could be used at the substation level (10 MW) close to the load centers with some savings in electrical transmission cost compared to pumped hydro storage and peaking systems. Capital costs for electrochemical energy storage would have to be competitive with pumped hydro ($100-$150/kw) and achieve similar overall efficiency of 65 to 70 percent.

Environmental Burden. The use of electrochemical energy storage would provide an increase in pollution level at the central station proportional to the inefficiency of energy storage as for pumped hydro storage. However, the added pollution load (atmospheric, thermal pollution) would be more uniformly distributed over 24 hours. Elimination of older inefficient fossil-fueled plants might be achieved by increased use of energy storage. Reduced atmospheric pollution would be realized by energy storage in combination with nuclear plants that are most economic at high load factors. Whereas, pumped hydro has limited applicability because of lack of suitable sites that are technically and environmentally acceptable, there would be no such limitation on the use of electrochemical energy storage near load centers.

Since there is presently a large installed electric generating capacity to meet variations in load (~50 percent load factor for the United States), up to 25 percent of the U. S. capacity could be electrochemical energy storage if an economical system were available.

Hydrogen

A great many comments have been made recently relative to a "hydrogen economy" and an overview is provided in this Appendix. Here the storage of hydrogen is discussed. Most of these are based on the clean-burning characteristics of hydrogen where water is the main product of combustion. But, since air is usually the oxidizer, appreciable amounts of NO may also be formed if the hydrogen is burned in conventional equipment. Fuel cells or low-temperature catalytic combustors will eliminate the NO problem with hydrogen systems, but both of these energy-conversion devices will require a great deal of development before they reach large-scale acceptance.

A major advantage of hydrogen is that it can be stored in exactly the same fashion as natural gas--usually in selected underground formations from which natural gas has been taken. Like natural gas, or a tank farm storing residual fuel oil, or even a coal stockpile, such an underground formation does store energy but in a form which must be converted into electricity or shaft horsepower or heat. Nothing in the characteristics of hydrogen make it superior as such an energy storage system except that it can be produced by electrolysis of water by off-peak electricity, and hence it has all the attributes of pumped storage. Electrolysis is, presently, neither low cost nor highly efficient, but if the nuclear power plants of the future must be operated as base-load stations, then electrolysis may one day look more attractive economically than it does today.

As far as storage characteristics are concerned, hydrogen has two properties that make it less desirable than natural gas--its low molecular weight that favors diffusion through underground formations that can hold natural gas with few losses, and its low calorific value of only 330 Btu/ft^3. Hence, volume wise, a storage system based on hydrogen would have one-third the capacity of the same system with natural gas. Storage of hydrogen in liquid form almost of necessity will require the construction of special storage reservoirs because of the very low temperature of liquid hydrogen,--253 C.

Hydrogen, then, can be stored like other gaseous fuels, and with some advantages and some disadvantages compared with other energy sources. Since it provides a highly reactive fuel, relatively easy to convert into useful forms of energy, hydrogen in some respects is superior to natural gas, residual fuel oil, and coal, all of which are easier to store than hydrogen. A major advantage of hydrogen is that it can be produced readily from off-peak electricity, but at a penalty both in dollars and in efficiency that may well limit its wide use.

Environmental Burden. The environmental burdens are very similar to those associated with underground storage of natural gas (Appendix F) leakage hazards, and combustion pollutants associated with gas compression equipment prime movers.

Compressed Gas

Compressing air during off-peak hours, and expanding the air through energy-recovery systems during maximum demand, is a promising, though little developed, energy-storage process. Using natural underground formations appears preferable cost-wise to building pressurized tanks of the required size.

A unique system involving a gas-turbine has been described by Harboe(X-29) in which air stored under pressure in a gas-turbine cycle at one time utilized later in the combustion/expansion part of the cycle. The air may be compressed using electricity generated during off-peak hours. In this fashion, utilizing this stored air, the gas turbine can produce as much as three times more power than if it had to drive its compressor during send-out.

Cost-wise, such air storage systems should be appreciably less expensive than other systems in meeting peak-load demands, where output is demanded for less than 3000 hours per year. According to Harboe's analysis, send-out costs for air storage are about the same as for pumped storage at 3000 hours per year at 6 mills/kwhr. For lesser operating hours per year, air storage costs remain nearly constant at about 6 mills while other conversion systems become much more expensive.

Environmental Burden. Effects in the environment attributed to the gas-turbine part of this storage system would be only a third that if the gas turbine also compressed its combustion air. The total environmental emission would depend on the system providing off-peak electricity.

Thermal Storage

No suitable means has yet been developed for storing useful amounts of thermal energy. Most advances have been made in residential solar-heated homes, where surplus heat stockpiled in beds of gravel or in Glauber's salt can provide heat for short periods of sunless days. Other materials with a high heat of fusion or which undergo a phase change at useful temperatures have been proposed, but a completely satisfactory system has yet to be devised. For residential heat storage, huge beds of gravel filling what normally would be basement space have proved to be most practical for storing heat provided by air circulating through solar-heated collectors on the roof of a residence.

Little opportunity exists for devising a practical system for converting such thermal energy into electricity or shaft horsepower, largely because the Carnot-cycle efficiency will be low for the moderate maximum temperature of the working fluid reached in most heat cycles. Utilizing halogenated hydrocarbons or such fluids as butane and propane, thermal storage to be used later makes more sense, but the costs are expected to be high. The field of thermal energy storage has been explored quite thoroughly. In general, it appears to have little promise if the eventual goal is to generate electricity or mechanical output.

Waste Heat Recovery

Because of thermodynamic limits on the efficiency with which heat energy can be converted to work energy, electrical power generating stations must create more heat energy than the electric power they produce. The unused heat must then be disposed of, presumably to a water body or to the atmosphere. For example, a modern nuclear power generating station operates with an efficiency of approximately 32 percent. For every unit of electrical energy produced, two units of heat energy are discarded as waste heat. Although the thermal impact of this waste heat on the environment can be a significant problem, the concept of waste heat recovery is not directed at reducing the effect of waste heat on the environment but rather at making better use of this great energy resource.

Finding uses for waste heat is not as easy as it might first appear. The temperature of the waste heat from the power plant is often as low as 80 to 100 F. There are not many processes that can make productive use of temperatures this low. In a sense finding uses for waste heat is nearly equivalent to finding means of beating the Second Law of Thermodynamics. As a result many of the more promising applications of waste heat are closely associated with biological comfort rather than mechanical or chemical processes.

Consideration of waste heat recovery should not be restricted to those processes which can only make use of temperatures in the 80 to 100 F range; however, waste heat can be rejected from the power station at higher temperatures in the form of low-grade steam. Although this results in a poorer-efficiency for electrical power generation, the benefits from the process and the electrical power generation may in a combined sense have made better use of the energy resources. On what basis should a use of waste heat be considered sufficiently productive to be employed? In the present system, the yardstick is purely financial. Unfortunately, the present economic system probably places too low a value on our limited energy resources. If a national energy policy were to place higher priorities on better utilization of fuel resources, many more uses of waste heat could be more readily justified than are possible today using financial criteria.

A number of the uses of waste heat that have been investigated are presented in the following paragraphs:

Central Heating and Air Conditioning

The use of low-grade steam for heating residences and stores has been employed in some cities for a number of years. Since the steam can be transported economically for only a few miles, the practical use of steam for central heating requires proximity of the power station to a large population. Conversely, the potential environmental effects of nuclear and fossil fuel plants encourage more remote siting. Air conditioning through the absorption process can also be a practical use of low-temperature steam. This use can be particularly effective in reducing electrical power needs in regions controlled by summer demand. Some investigation has been performed on "new city" concepts intentionally designed around small nuclear power plants in order to provide heating and air conditioning. An underground reactor in a suburb of Stockholm, Sweden, is used for residential heating in this manner.

On a smaller scale "total energy systems" should be considered as a productive use of waste heat for central heating. A completely enclosed community has been designed for Alaska which is the ultimate extrapolation of the total energy concept.

Water Treatment

Combined power generating stations and desalination plants have been given a great deal of attention. Bolsa Island, a proposed nuclear station of this type, was eventually dropped because of financial considerations. This use of waste heat does hold promise for the future, however, either in the production of drinking water or water for irrigation. Similarly, the use of waste heat has been suggested for sewage and waste water treatment. Distillation can be employed to separate the water from contaminants in the waste water. It has also been suggested that heating of sewage can be used to speed up the biological processes of waste treatment.

Industrial Processes

Few chemical or mechanical processes can make use of very low-grade heat. There are, however, applications for process steam extracted at higher temperatures that should be considered as a use of waste heat. The Dow Chemical Company will make use of steam extracted from a nuclear power plant under construction in Midland, Michigan, for the production of chemicals. A similar arrangement is planned in Germany at the BASF plant.

Agriculture

Some of the more promising uses of waste heat are in the area of agriculture. Waste heat can either be employed to extend the growing season for plants or to improve production by maintaining temperatures close to the optimum for growth. Water, used for both irrigation and heating, can be sprayed over the plants or used to heat the soil through subsurface pipes. Investigation of these techniques is underway in the Pacific Northwest. Waste heat can also be employed in the heating and cooling of greenhouses for the production of high value crops.

In a similar fashion the heating of animal shelters has been suggested as a means of decreasing feed consumption and increasing productivity. The effects of climate control on poultry and swine productivity have been studied and the results indicate that significant improvements can be achieved. To be practical, however, farms would have to be located within close proximity to the power stations. Furthermore, even if all of the swine and poultry in the country were to be grown in this fashion it would represent a usage of only a few percent of the available waste heat from electrical power production.

Aquaculture

Aquaculture represents another promising application of waste heat. Growth rates for many fish, crustaceans and shellfish are quite temperature dependent and productivity can be greatly improved by maintaining temperature control. There are a number of successful commercial demonstrations of aquaculture which include catfish, trout, shrimp, and oyster production. A classic example of the use of waste heat is provided by the commercial production of oysters in Long Island Sound in the effluent of the Long Island Lighting Company. This example also shows the potential conflict between aquaculture and preservation of a natural environment. Recent state environmental protection laws limit power plant effluent temperatures to below the temperatures of value in promoting oyster production. Once again degradation of the natural environment must be weighed against the productive usage of energy.

Miscellaneous Waste Heat Recovery Uses

A number of diverse uses can be identified for waste heat. Often these uses involve a very small fraction of the available energy or have very restricted application. For example, it has been suggested that waste heat be employed in clearing snow from city streets or the runways of airports. Low-temperature steam also has been proposed as the motive force for urban mass transportation systems.

In conclusion, waste heat recovery as a means of better utilizing our energy resources does hold some promise particularly in the areas of heating and air conditioning, agriculture and aquaculture. There are only a few examples where a clear financial incentive exists to exploit this energy resource in today's economy. A more realistic assessment of the value of our fuel resources to future generations would, however, indicate the need for more efficient use of these resources and would enhance the benefits to be gained from waste heat recovery.

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